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CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E-01933A-12-0291

Exhibit #: TEP8, Votesolar1, Votesolar2
ZWick1, ZWick2

Part 9 of 9

Arizona Corporation Commission
DOCKETED

MAR 13 2013

DOCKETED BY JM

EXHIBIT
TEP-8

Tucson Electric Power Company - Residential Bill Impact			
Average Monthly (767 kWh)	Current	Settlement	Difference
Customer Charge	$7.00	$10.00	$3.00
Delivery Charge	41.87	45.90	4.03
Fuel	28.73	24.61	-4.12
Bill (Excluding REST & DSM)	$77.60	$80.51	$2.91
REST	3.80	3.80	0.00
DSM	0.96	0.34	-0.62
Bill (Including REST & DSM)	$82.36	$84.65	$2.29
Base Fuel Charge	$22.83	$25.67	$2.84
PPFAC	5.90	-1.06	-6.96
Net Fuel	$28.73	$24.61	-$4.12

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-12-0291

EXHIBIT
VoteSolar-1
ADMITTED

DIRECT TESTIMONY OF RICK GILLIAM

ON BEHALF OF THE VOTE SOLAR INITIATIVE

JANUARY 11, 2013

Introduction

Q. Please state your name and business address.

A. My name is Rick Gilliam. My business address is 1120 Pearl Street, Suite 200 in Boulder, Colorado.

Q. On whose behalf are you submitting this rebuttal testimony?

A. This testimony is submitted on behalf of The Vote Solar Initiative ("Vote Solar").

Q. By whom are you employed and in what capacity?

A. I serve as Director of Research and Analysis for Vote Solar, and oversee policy initiatives, development, and implementation.

Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement the key policies needed to integrate solar into the marketplace. We have nearly 2,500 Arizona members with 269 within TEP's service territory.

Q. Please describe your experience in utility regulatory matters.

A. Prior to joining Vote Solar in January of 2012, my regulatory experience included five years in the Government Affairs group at Sun Edison, one of the world's largest solar developers, twelve years at Public Service Company of Colorado (PSCo or the Company) as Director of Revenue Requirements and twelve years with Western Resource Advocates (WRA – formerly known as the Land and Water Fund of the Rockies or LAW Fund) as Senior Policy Advisor. Prior to that, I spent six years with the Federal Energy Regulatory Commission. All told, I have in excess of 30 years of experience in utility regulatory matters. A summary of my background is attached as Appendix A.

Q. Have you previously testified before the Arizona Corporation Commission ("ACC" or "Commission")?

A. Yes. I testified before this Commission on behalf of the LAW Fund in some of the early proceedings regarding the development of a renewable standard, and have participated in a number of rulemakings in the intervening period.

Q. Before what other utility regulatory commissions have you testified?

A. I have testified in proceedings before the Public Utilities Commission of Colorado, Nevada Public Utilities Commission, the New Mexico Public

Regulation Commission, the Utah Public Service Commission, the Wyoming Public Service Commission and the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Arizona Corporation Commission (ACC) with Vote Solar's perspective on how the the cost recovery and rate design proposals of Tucson Electric Power (TEP) may affect current solar customers and future solar adopters in TEP's service area.

Q. Please summarize your testimony.

A. Utilities across the country, including TEP, are experiencing major changes and shifts in the way customers use energy. Growth in retail sales on an aggregate basis, is slowing across the U.S., due largely to reduced economic activity coupled with increased deployment of demand side management technologies and distributed generation resources. According to the U.S. Energy Information Administration (EIA), total delivered electricity use in all sectors is predicted to increase at an annual growth rate of 0.7 percent per year from 2010 through the year 2035.[1] Furthermore, The EIA projects that both distributed generation solar (DG solar) and microturbine electric generation additions between 2010 and

[1] Faruqui, Ahmad and Eric Shultz. "Demand Growth and the New Normal: Five forces are putting the squeeze on electricity consumption" Public Utilities Fortnightly, December 2012; < http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal/page/0/1?authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98>.

2035 will outpace the growth in conventional natural gas-fired cogeneration, wind, and fuel cells.[2] TEP is not immune to these meta changes, being felt by utilities across the nation. TEP like many utilities is seeking incremental changes in certain aspects of their business model to cope with a changing energy landscape. In this proceeding, TEP is proposing a number of structural changes to its retail rates in an effort to reduce the uncertainty and improve the stability of revenue recovery related to electric sales. In this testimony, I address three of those changes that will affect DG solar customers: the proposed increase to the monthly customer charges; the proposed increase in the demand ratchet for certain customer classes to 100%; and the Lost Fixed Cost Recovery Mechanism.

Q. Please characterize Vote Solar's interest in this TEP rate case.

A. A sizable amount of Vote Solar's work is focused on rate design issues related to distributed generation (DG) solar. Vote Solar is actively participating in net metering and broader rate design regulatory proceedings in states across the U.S, including: Arizona, California, Colorado, Minnesota, New Mexico, New York and Vermont among others. Our interest in this case is as follows: TEP's proposals in this rate case indicate that the utility is restructuring its rate design to account for higher penetrations of DG solar, and other energy reducing technologies. We believe TEP, and this proceeding, will establish new

[2] Ibid.

ratemaking concepts that other utilities may wish to follow. The trends experienced by TEP as outlined by TEP witnesses are not unique to TEP but rather point to over-arching shifts in the national utility landscape. Thus the outcome of this rate case has implications beyond Tucson and Southern Arizona, and we want to ensure that the decisions made in this rate case do not harm the potential for DG solar to play an increasingly large role in the TEP service area, or even the national landscape. Trends highlighted in this case include:

- Reduced sales growth: As a result of many different factors including the economic recession, increased customer efficiency, increased self-generation, the growth in sales is projected to be below historical norms.
- Increased cost growth: Additional costs are being incurred by TEP to serve its customer base, both in terms of investments and increased cost of operations, regardless of the amount of sales growth anticipated;
- Increased environmental concern: in the wake of hurricane Sandy, and Irene and Lee before it, there is increased awareness and concern about the effects of climate change. There could soon be additional federal pressure to reduce carbon emissions, including reducing emissions from its conventional coal burning fleet of generators.
- Increased consumer preference for clean resources: there is great popular support for increasing the amount of clean energy in the mix of resources used to generate electricity in TEP's service area in Arizona, and even nationwide.

Commissions are rightly concerned about the effect of these trends on the retail electric rates that customers will be asked to pay. In this proceeding, there are certain rate proposals that represent changes to TEP's cost recovery mechanisms, which would impact the ability of TEP's retail customers to install solar on their homes and businesses. It is these changes that specifically interest Vote Solar.

Q. Please describe some of the popular support for clean renewable resources in Arizona.

A. According to an article in the Arizona Journal on September 19 of this year, "four separate public opinion surveys conducted in May 2011 by APS and the Morrison Institute for Public Policy revealed that 94% of APS customers support increasing the use of solar energy." In TEP's service territory, a utility-conducted poll found that 73% of respondents agreed or strongly agreed that "it is important TEP uses all types of renewable resources including solar, wind, geothermal, hydroelectric, biomass and biogas, to provide energy to their customers." Additionally, 74% agreed or strongly agreed that; "it is important TEP uses solar power as the primary renewable resource to meet its renewable energy requirement."

Q. What is TEP's view of the effect of recent economic conditions?

A. In response to discovery, TEP stated as follows:

> "TEP believes that the weak economic conditions that have existed for the last several years have contributed to load and sales reductions. These conditions have created residential and commercial vacancies and caused individuals and businesses to look for new ways to keep down their costs. TEP believes that these cost reduction efforts include conserving their utilization of electricity, and thus impact sales. However, TEP does not have any specific studies to estimate the magnitude of impact that the economic downturn has had on sales."[3]

Q. Can the effect on electricity sales of the recession be estimated?

A. Yes. By comparing actual pre-recession sales growth rates with growth rates in-recession and accounting for sales reduction related to efficiency and distributed generation, the effect of economic conditions over the last five years can be estimated.

2000-2007 growth rate	2.3%	TEP/Bonavia, p. 6
2007 Retail Sales	9,634 GWh	2007 Form 1
Estimated 2011 sales with pre-recession growth rate applied	10,551 GWh	
Actual 2011 Sales	9,332 GWh	2011 Form 1
Estimated total sales reductions	1,219 GWh	
2011 sales reductions related to EE	66 GWh	TEP/Bonavia, p. 7
2011 sales reductions related to DG	89 GWh	TEP/Bonavia, p. 7
Estimated sales reduction effect of economic conditions	1,064 GWh	

[3] TEP response to VSI 1.22

From this "back of the envelope" analysis, it is clear that sales reductions related to energy efficiency programs and distributed generation are minor compared to those related to economic conditions – only 5% and 7% respectively. This analysis also does not take normal weather into account. The cooling degree days in 2011 (both for that year and on a ten year rolling average basis) are higher than those in 2007, the implication being that hotter than normal weather helped to increase sales in 2011.

Q. Should the level of sales growth remain very low to zero as a result of the aforementioned factors, would there be some constant level of costs to provide electric utility service that can be achieved?

A. It doesn't appear so. There are certain costs that will continue to increase:

"Given the need to replace components of the infrastructure costs increase because of the replacement of fully depreciated capital items with new equipment that has higher costs just because of inflation. Further, the assumption of constant load does not mean that new investment to connect new customers is not occurring. This new investment costs more than the average cost included in rates. Constantly changing environmental regulations require the investment in new facilities to meet those requirements. The net result is increased rate base and thus higher revenue requirements to support capital. In addition, expenses also increase over time due to a variety of factors such as inflation, government mandates and other factors beyond the reasonable control of the utility such as healthcare costs, postage, taxes and so forth.[4]

[4] TEP response to VSI 2.21

In summary, TEP indicates "*constant, or flat, electric sales over five years do not translate equally to flat capital investments or flat O&M expenses.*"[5]

Q. Do you have examples of cost increases since the last rate settlement?

A. Yes. TEP noted the following major O&M increases between 2006 and 2011:[6]

Payroll:	$ 6.8 million
Overhaul and outage normalized expenses:	$ 6.3 million
Pension costs:	$ 4.6 million
Transmission cost:	$ 5.9 million
Outside Services:	$ 4.1 million
Total	**$27.7 million**

While one would hope that some steady state level of expenses (including return on assets) could be reached for a static level of sales, current experience appears to run counter to this ideal.

Q. What are the implications of these cost increases combined with the sales reductions that TEP describes?

A. Recent sales reductions due to a variety of causes puts significant pressure on TEP's ability to maintain its desired earnings levels, especially in an environment where costs continue to increase. It's difficult to predict, for example, what the new "normal" level of sales growth will be over the longer term when the

[5] TEP response to VSI 1.38 (see also VSI 1.07)
[6] TEP response to RUCO 2.04

economy recovers, compounded by the question of whether the extreme weather experienced during the test period is the new *normal*. However, if the normal level of sales growth is substantially less than the 2.3% that TEP enjoyed pre-recession and costs continue to grow, the unavoidable result is a series of significant rate increases under the traditional regulatory model.

Q. Is there any way to estimate future potential rate increases?

A. There are many variables that impact the costs of providing electric service, however the current increase request could be representative of future increases if current conditions persist. Indeed, capital additions are expected to increase over the next five years to a level about 50% higher than those of the last five years.[7]

Q. What factors might cause TEP to have increased sales, offsetting recent historical trends?

A. Sales can increase as a result of a revitalized economy (both electricity use per customer and number of customers), new "must-have" home appliances such as plasma screen TVs, and importantly, increased penetration of electric vehicles. Additionally, increasing frequency of extreme weather will cause increased use of air conditioning equipment, and hence sales will likely increase. While the 2011

[7] See TEP witness Larson Direct Testimony, page 13, lines 6-8.

test year may be "extreme" in terms of cooling degree days when compared to a ten-year average, it may in fact represent the new normal. Each of these changes would increase sales from test year levels and result in margin improvement for TEP.

Q. How is TEP proposing to deal with these trends?

A. In its Application and subsequent discovery, TEP describes its efforts to manage its costs, but there is no real strategic change in operational direction discernable in this rate filing by TEP. TEP witness DesLauriers suggests that the challenging operating conditions including the economy, regulatory requirements, and effect of new technologies, will impact TEP over the near and medium terms.[8] TEP continues to operate itself under essentially the same traditional business and regulatory model virtually all regulated utilities have used for decades. It does however seek several new rate mechanisms to provide quicker and more stable recovery of its costs as a means of reducing earnings uncertainty related to conventional retail electric service in this changing world. In other words, TEP is not addressing the underlying structural changes but rather some of the symptoms.

[8] Direct Testimony pages 10-13; note that near and medium terms are undefined.

In addition to the conventional adjustments to its test year for in-period and post-period changes, TEP is proposing a number of changes in its revenue recovery strategies that would increase the certainty of it recovering certain perceived revenue shortfalls including:

- Transferring recovery of certain demand-related costs from the existing mechanism (sales or demand-based, depending on class) to the flat monthly customer charge;
- Modifying the existing 50% or 66% C&I demand ratchet to a 100% ratchet;
- Imposition of a limited decoupling mechanism known as the LFCR applicable to all rate classes other than water pumping and lighting; and
- Imposition of a rate rider mechanism to recover capital and operating costs related to environmental controls on existing coal plants.

Given the changing world TEP itself describes, in order to avoid a long series of rate increases, we believe the Company and the Commission should begin consideration of new paradigms of utility and regulatory operations in which sales growth is minimal, capital investment is limited to connecting new customers and replacing worn out assets, and expense growth is related primarily to inflationary levels. Minimizing significant capital additions in the future reduces the risk of future non-maintenance related stranded assets.

Q. What should TEP be considering?

A. TEP is among the first utilities addressing this changing world in the near term. Indeed, a recent report[9] from the Deloitte Center for Energy Solutions – *The math does not lie: Factoring the future of the US electric power industry* - addresses these very issues and concludes electric companies should rethink their strategies, and consider options that include very strict management of the "numerator," i.e. the cost side of the equation, new regulatory structures and initiatives, development of new regulated revenue streams, and consideration of innovative business models and non-regulated business expansion.

Q. Is TEP moving in this direction in this proceeding?

A. Yes, it is to an extent. TEP describes in its testimony its cost management efforts. Additionally, TEP proposes a partial decoupling mechanism providing a new rate recovery structure that begins to address future sales uncertainty. In addition, implementation of the Smart Grid, initially through meter upgrades, will provide additional information about customer behavior and effects on the grid providing the potential for more efficient operations. However, TEP's investment in smart meter deployment represents only about 1.3% of total regulated investments over the last four years. The following chart provides the status of smart meter deployment.

[9] See http://www.deloitte.com/view/en_US/us/Industries/power-utilities/24d2878b0898a310VgnVCM2000003356f70aRCRD.htm

Deployment of "Smart" Meters[10]	Interval Meters	% of Total	Projected Completion[11]
Residential	112,119	29%	6 years
Commercial	16,276	42%	5 years
Industrial	108	100%	Complete
Distribution Feeders	277	68%	Complete[12]

The problem we have today is that we simply don't know how persistent current conditions will be, and how they may change in the future. TEP should be commended for moving in this direction and encouraged to build out its advanced metering infrastructure to provide increased transparency and data availability to further improve opportunities for increased efficiency in operations, and to help develop more effective rates and cost recovery mechanisms in the future.

Q. Do you have concerns with any of the new proposals set forth by TEP in this proceeding?

A. Yes. I will address three proposals – the increase in the monthly customer charge, the increase in the demand ratchet, and the partial decoupling mechanism.

[10] TEP response to VSI 2.02.
[11] TEP response to VSI 3.02
[12] Ibid, TEP indicates "The remaining 131 feeders have meters that provide the data needed at this time. There are no plans to replace any of the remaining 131 meters with Smart Meters."

Proposed Increase to Monthly Customer Charge

Q. Please describe the change to the customer charge proposed by TEP.

A. For virtually all rate classes, including those with demand-based charges, TEP is proposing to recover a portion of demand-related costs through the monthly customer charge, aka service and facilities charge, to remedy revenue instability.

Q. Is this a common practice for the recovery of non-customer-related costs?

A. Generally not. Common practice is to recover costs incurred by the sheer existence of an individual customer in the customer charge. This would include costs such as meters, meter-reading, billing and collection, and so forth. These are costs caused by the number of customers being served independent of the consumption or power demands of the individual customers. Other non-customer related costs of providing service are generally recovered on a volumetric basis either on the volume of kWh or kW depending on class.

Q. Why is TEP proposing this change?

A. TEP is concerned that "if customer usage falls, the Company will not have a reasonable opportunity to earn its authorized rate of return."[13] Additionally, TEP states that higher load factor customers pay a disproportionate share of the system costs under the current rate structure, and that this shift will help to

[13] TEP witness Jones Direct Testimony, page 29, lines 14-16

relieve that burden. *"If the Company can shift revenue collection away from energy charges, it can reduce the cross-subsidization that occurs when usage within customer classes varies significantly."*[14]

Q. What is your understanding of the term "cross-subsidization?"

A. A subsidy is created when the actual cost to serve a retail electric customer is different than the costs being recovered from that customer by the utility. Anytime the costs recovered from a customer, or from a class of customers, are different from the amount allocated or assigned to them during the previous rate case, a subsidy is theoretically created.

This can become a complex equation as the cost allocation process to assign class cost responsibility is inherently non-precise. This is further complicated because customers and customer classes tend not to be static, but to change usage and demand patterns over time. Thus, as soon as new rates are placed into effect, cross subsidization will begin to occur with some customers paying more and some less than their up-to-the-minute theoretically appropriate cost of service, were one to be performed at that point in time. A ready example is the diverse rates of return (and hence revenue requirements) by customer classes experienced by TEP as noted by TEP witness Jones: the Company's class cost

[14] TEP witness Jones Direct Testimony, page 31, lines 11-13.

of service study "shows that the residential and large light & power customers are being subsidized by the general service class."[15]

In an ideal non-subsidized world, each customer class would be assigned its precise cost responsibility, provide revenue equal to its allocated costs, and each customer within the class would be at the exact mean for the class. Alternatively, a full cost of service study could be performed for each and every customer. As neither option is realistic, we should recognize and acknowledge that the estimates and approximations made for the sake of administrative ease yield results assumed to be just and reasonable without straying into the bounds of "undue discrimination."

Q. Do you have concerns with the TEP proposal?

A. Yes. First, it is important to remember that changes in sales can occur in both directions, as outlined above. The sales reduction impacts of the recession have laid bare a downside for the utility of the current structure, i.e. recovering costs on a basis that is different from the causation of the cost. Conversely, increases in sales between rate cases such as those that result from weather warmer than "normal" (in a rate case context) will result in the potential for the utility to earn in excess of its authorized return. This structure results from a regulatory balance

[15] Direct Testimony, page 4, lines 9-10.

that has evolved over many years and departure should be made carefully and thoughtfully.

Second, an increased flat monthly unavoidable customer charge, coupled with lower marginal energy costs reduces the incentive for a customer to be more efficient with its energy use. It does not promote conservation as suggested by TEP.[16]

Third, TEP is not suggesting that certain *specific* costs be moved from recovery through the variable rate to the monthly flat customer charge. It is suggesting that the customer charge be increased by seemingly arbitrary amounts not tied to specific costs, but rather as a matter of policy and revenue stability. Further, the testimony of its witness Jones suggests that it will continue moving towards full non-fuel cost recovery in the monthly customer charge for customers on volumetric rates (see generally Jones Direct testimony, page 33), known as a "straight fixed-variable" rate structure. TEP should be required to demonstrate, and the Commission approve, the nature of any specific costs sought to be recovered through a customer charge, that clearly shows that such costs are more closely related to the existence of the customer than to the consumption (size) of the customer.

[16] TEP response to VSI 2.25: "Importantly, the change in cost recovery moves to more economically efficient rates that allow the customer to know the real economic value of conservation as opposed to a value that overstates the savings from conservation and results in higher rates for all customers."

Fourth, TEP's purported goal is to reduce a cross subsidy between high and low load factor customers. However, this change simply establishes a different cross subsidization whereby everyone pays for a portion of fixed costs on a flat monthly basis regardless of the fixed costs required to serve the customer. In the extreme, TEP's straight fixed-variable rate structure would charge every customer in a class, regardless of size, the very same amount for demand-related costs, resulting in a fuel-only variable charge in the 3-4 cent range per kWh, and a monthly customer charge of $55 for residential and $362 for the Small General Service class.[17] This approach would impose a significant cost burden on small customers and a major subsidization of larger customers within the class.

Finally, the claim that higher load factor customers pay a disproportionate amount of system costs is based on an assumption that the amount that customers pay for electric service is the precise cost of serving them individually. This is simply not true.

Q. Why do you say that rates are not precise?

[17] From workpapers: 2012 Schedule G 12-31-11 (Revised 10-05-12); Sheet G-6-1 Unit Cost.

A. In regulatory circles, it is often said that ratemaking is an art, not a science. The process of determining revenue requirements, classifying and allocating costs, and designing rates is full of assumptions, estimates, modeled data, statistical methods, and adjustments made in a legitimate effort to spread cost responsibility to customer classes based on causation, and achieve a reasonably consistent relationship between costs and revenue so that the utility can have an opportunity to recover its costs and earn its authorized return on equity between rate cases. Moreover, even accepting all the approximations in the process, the rate for a class is designed for that mythical customer that represents the weighted mean of the group. This is not intended to be an indictment of the regulatory system - there are very good reasons why the process has evolved to the current structure. However, as we start to make selective changes that move away from current structures and practices, we should carefully examine the bases for doing so and the consequences.

Q. Please elaborate.

A. As described by TEP, rates are the result of a multi-step process of functionalizing costs, classifying costs, and allocating costs to customer classes. Each step is designed to group expenses (including a weighted return on rate base) into categories with similar cost incurrence characteristics for later allocation. In the end, there are only three things about a customer that can be measured and thus billed – (1) the customer exists, (2) the amount of energy the customer consumes in a billing period, and (3) the maximum amount of energy that customer uses in a defined period (usually 15 minutes). The third item is sometimes tracked for every 15-minute period throughout the billing period for large customers and those on certain rate forms that differentiate demand charges by time of day. As a result, all utility costs must be recovered on the basis of one, or a combination, of these three parameters.

Conveniently, costs are generally incurred because (1) customers exist, (2) electricity must be generated to be consumed each hour of each day, and (3) sufficient capacity must be available to serve the maximum load imposed on the system, plus a reserve margin.

The principle of cost responsibility related to cost causation is a basic underlying principle of utility ratemaking. This is noted by TEP witness Jones on page 17 of his direct testimony:

> *The allocation factor should be based upon an equitable method that harmonizes the cost-causation with the functional cost being considered. In other words, the allocation should be done in a way where the cost-causation for the functional cost considered is properly identified.*

And also in response to Vote Solar discovery question 2.03:

> *Given the load characteristics of each class of service (class coincident peak and class load factor) different methods will allocate more or less costs to each class of service. The appropriate cost allocation method is*

> *the one that most clearly recognizes cost causation based on the operating, planning and system characteristics of the utility. Accordingly, TEP believes that the Average and Peaks method is most suitable.*

Drawing heavily on the criteria of a sound rate structure developed by Bonbright in Principles of Public Utility Rates,[18] TEP witness DesLauriers confirms the importance of cost causation (page 14):

> *Rate Equity & Non-Discrimination – This concept requires that prices should be designed to be just and reasonable and avoid undue discrimination. Having rates that reflect cost causation and the recovery of costs that arise from customers taking utility service promotes equity and non-discrimination.*

Similarly, the "NARUC Electric Utility Cost Allocation Manual" (NARUC, 1992) begins its description of the design of rates as follows:

> *Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant.*

It should be clear that cost causation and cost recovery are regulatorily "joined at the hip."

Q. How does cost causation affect this cost recovery issue?

A. There is sometimes a tension between cost causation and the means of cost recovery. For some costs incurred by utilities, the causation and recovery are very well aligned – a good example being fuel costs. Another example of good alignment is the cost related to an individual customer – metering, billing, etc.

[18] Bonbright, James, Principles of Public Utility Rates, Public Utilities Reports, Inc., 1988

Other costs are not so well aligned and require judgment. For example, non-fuel production costs (representing the largest portion - about 59% - of total non-fuel costs) and transmission costs (about 20% of total non-fuel costs) are allocated to customer classes based on the Average and Peaks method in which a portion of the costs are assigned on average customer class demand (also known as energy consumption) and the remainder on the class's contribution to the four monthly summer peaks. In TEP's words, "The Average and Peaks method recognizes the importance of the role of energy use in optimal system planning." Further, TEP addresses the cost causation relationship as follows: "The Company's average and peaks approach recognizes that plant is not just built to serve demand, but also to supply energy."[19] Moreover, the other component of the "Average and Peaks" method assigns costs to customer classes based on each customer class's *contribution* to the relevant system peaks – in TEP's case an average of the four monthly summer coincident peaks. This selection "most clearly recognizes cost causation based on the operating, planning and system characteristics of the utility."[20] It must be recognized however, that the only data available for many customers on demand-based rates is the maximum demand during a billing period. Since interval data is not recorded, load research estimates of class contributions are made to develop the necessary allocation information. The reality is that the coincident/non-coincident demand relationship

[19] Response to VSI 2.03.
[20] Ibid.

varies across different types of commercial and industrial customers that generally populate the classes with demand charges. This is an example of an approximation used for convenience.

In sum, the Average and Peaks method is based on the presumption that production and transmission costs are incurred to meet *average demand* (energy) in part and the four monthly system peak demands in part, generally all production and transmission costs (about 79% of the total) are recovered through a demand charge (if there is one) tied to the individual customer's maximum (non-coincident) peak load each billing period.

Similarly for distribution costs, the vast majority of costs are allocated to customer classes on the basis of non-coincident peaks. Here too, distribution systems are not built to meet the sum total of all customer loads but rather the aggregated load on each circuit. The major benefit of aggregating loads is to capture load diversity – the fact that different customers have differing load characteristics and will experience their peak loads at different times. As a practical matter determining the coincident load contribution to the peak load by circuit would be a monumental task so the NCP method has been generally accepted as a proxy. Again, there are good reasons this method is used, but it should not be assigned any more precision than it deserves. One final point –

distribution costs are mostly rolled together and allocated across all customer classes, regardless of the actual cost of the portion of the distribution system installed and maintained to serve a particular customer - another approximation for convenience and administrative simplicity.

Q. Please summarize the relationships among cost causation, cost allocation, and cost recovery.

A. Keeping in mind that rates are based on what is presumed to be a representative test period in which the relationships will remain somewhat constant between rate cases, the following are the key takeaway points:

- Cost causation: the goal of cost allocation is to assign costs to the broad customer classes based upon the reason that the cost was incurred;
- Use of estimates and approximations: allocation of costs on the basis of class coincident demand is logical from a causation standpoint, but of necessity is based upon estimates of the class demands at the time of the system peak demand;
- Rate design: designing rates for classes containing customers that may be similarly situated, but have some diverse characteristics will create equity issues between those above and below the mean;
- Cost recovery: recovery of costs on a basis other than cost causation can result in cross subsidization within a customer class;

Q. Given these explanations and examples, what is the effect of moving demand related costs to the monthly customer charge?

A. Under current circumstances, there is a limited universe of billing parameters available for recovering costs from small customers such as residential and small commercial – those with only an energy meter. The utility can recover costs on the basis of energy consumed or as a flat fee. Since the nature of the costs TEP seeks to recover through the monthly fee is unspecified, it is not possible at this time to say whether such costs are more closely related to the existence of the customer (would argue for the customer charge recovery) or the size of the customer (would argue for continued energy charge recovery).

Q. Are there other sources of subsidies outside of those inherent in cost allocation and rate design?

A. Yes. For example, rates that promote certain behaviors are often seen as good for the general public as a whole, whether it is using energy more efficiently, encouraging clean generation such as solar and wind, discounting rates to attract businesses to the region, or other special rates for new technologies like electric vehicles. These types of programs can result in individuals paying more or less than their share of the utility's costs allocated to his or her customer class.

Q. With this context, please summarize your concerns about the TEP customer charge proposal.

A. Current recovery methods are well established. TEP has not presented sufficient evidence at this time to justify a departure from existing practices. Moreover, the proposal is inconsistent with the basic principle of recovering costs based on cost causation set forth by TEP, NARUC, and Bonbright. Indeed, TEP is not delineating any particular demand-related costs it believes are appropriate for recovery through the customer charge, but rather proposes that this be the first gradual step towards recovery of all demand-related costs through the customer charge.

Q. What is your recommendation with respect to this issue?

A. I recommend that TEP's proposed change to the Customer Charges as submitted be rejected in this proceeding. However, TEP should be required to submit a report outlining the specific demand-related costs it believes should be recovered through the customer charge, along with narrative support. Through a brief set of workshops, I believe accommodation can be reached on this issue and new tariffs can be filed without the necessity of a comprehensive rate change filing.

<u>Proposed Increase to Monthly Demand Ratchet</u>

Q. Please explain what a demand ratchet is.

A. A ratchet is a minimum bill structure applied to customers that are billed in part on a demand basis. The billing demand for a customer is the greater of the customer's actual demand or a set percentage of its maximum demand over a past period – usually 11 months.

Q. Please describe the TEP demand ratchet proposal.

A. TEP is proposing to increase the demand ratchet for commercial and industrial customers to a uniform 100% of each customer's maximum demand in the prior 11 months. Similar to its proposal to add demand related costs to the customer charge discussed above, TEP justifies this proposal as a means of reducing the costs recovered from high load factor customers:

> *Higher load factor customers will pay less to subsidize lower load factor customer's less efficient use of the utility's system.* [21]

TEP believes the ratchet allows costs to be more equitably recovered from customers within a class with demand charges.[22]

Q. Do you agree with this assertion?

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[21] Response to VSI 1.28
[22] Response to VSI 2.26

A. No. A commercial or industrial customer's energy use characteristics (monthly demands and energy consumption) are reflective of the nature of their business operations. Such operations may be very consistent from month to month or may be more seasonal in nature. As discussed in detail in the previous section, a utility's costs of providing service are functionalized, classified, and then allocated to customer classes on the basis of cost causation. TEP assigned its costs to each customer class in this proceeding on the basis it determined best captured the reason for the cost incurrence. To the extent a low load factor customer may have lower loads in some months, and lower energy use, it contributes to fewer costs being allocated to the class as a whole. For the utility to then seek to collect higher costs from customers that have helped reduce the overall class cost burden is inconsistent. Moreover, it provides a double benefit for high load factor customers – first, they receive the benefit of lower overall costs being assigned to their rate class, and second, the unit rates are reduced (and hence their own monthly charges) by increasing the billing parameters for the lower load factor customers.

Q. Does a demand ratchet change the total amount of costs recovered from each customer classes?

A. No. It only changes the amounts each customer within the customer class pays for fixed cost recovery. Because the total level of billing determinants increases, the demand rate is reduced, all else being equal. Within a given rate class, a portion of customers will pay more and a portion will pay less. Either way TEP will recover all of its costs. TEP is trying to reduce the costs to high load factor customers at the expense of lower load factor customers.

By way of a simple example, let's suppose that two commercial customers have the same annual peak load. Customer A however is a high load factor customer running all of its equipment, including HVAC, 24 hours per day, while Customer B's operations are more typical matching the customer class weighted average demand and consumption relationship – in other words the load factor parameters for which the class rates are actually designed. Thus, under normal *non-ratcheted* demand cost recovery Customer B would pay the demand charges that cost causation, allocation and recovery deem appropriate for its class. Customer A would properly pay more because the designed rates would require a larger revenue contribution based on the approved cost causation and allocation bases. By implementing the ratchet TEP is proposing, both customers would pay the same amount towards fixed cost recovery, resulting in a subsidy of the higher load factor customer by the average load factor customer.

Q. Are there other effects on customers subject to the demand ratchet?

A. Yes. A demand ratchet effectively removes the incentive for the customer to improve the efficiency of its operations and thus reduce its peak demand. In other words, a customer is less likely invest in efficiency or distributed generation if it sees no benefits for a year.

Q. Is this proposal consistent with rate design principles outlined by TEP?

A. No. It is inconsistent with the principle of cost causation as a basis for allocation and cost recovery. It is also inconsistent with another principle TEP witness DesLauriers notes on page 14 of his direct testimony – that of administrative simplicity: "Customers should be able to understand the price signals provided by the bill and respond to those signals efficiently." Clearly, the ratchet does not fulfill this principle, unless the desired response is for the customer to freely demand more and more power up to the point of the highest demand over the past eleven months. Finally, in response to discovery (VSI 1.35), witness DesLauriers notes customers with similar cost profiles paying significantly different bill amounts "is a major problem because it violates the principles of Rate Equity and Non-discrimination and Cost of Service and Rate Efficiency." I submit that the equally important corollary to his point is that customers with significantly <u>different</u> cost profiles paying the <u>same</u> bills also violates these same principles.

Q. What is your recommendation for TEP's proposal to increase its ratchets to 100%?

A. I recommend the Commission reject this proposal in its entirety, based on (1) inconsistency with cost causation and rate design principles, (2) the creation of a new and maximized (by virtue of the <u>100%</u> feature of the ratchet) cross subsidy within the applicable rate classes, (3) exacerbation of the existing disparity between demands used for allocation and those used for billing, and (4) increasing the disincentive for customers to invest in technologies that can reduce demand.

Proposed Lost Fixed Cost Recovery Mechanism (LFCR)

Q. Please describe the TEP LFCR proposal.

A. The TEP LFCR proposal is a decoupling mechanism limited in scope that keeps the utility revenues whole with respect to reductions in sales related to two specific programs – energy efficiency and distributed generation.[23]

Q. How does the LFCR proposal work?

A. In short, TEP estimates the lost revenue associated with sales reductions related to these two programs and develops a rate rider to recover these amounts from all customers.

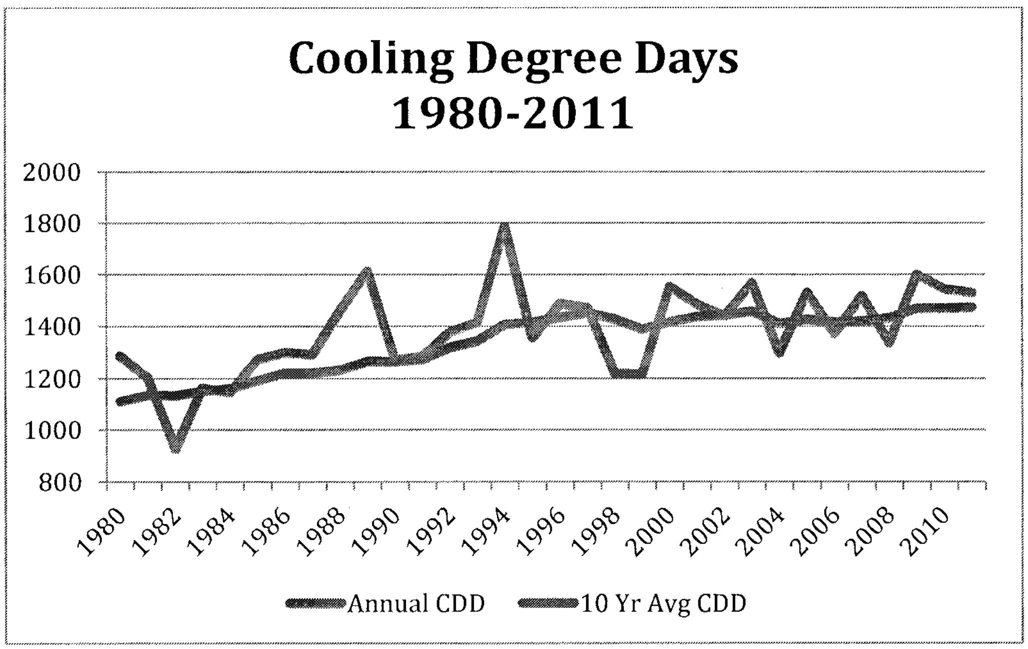
Q. Do you agree with the principles behind the LFCR?

A. I think a mechanism such as this could be helpful to address TEP's concerns about the volatility of revenue related to fluctuating sales levels. However, I do have concerns about this proposal, in particular the focus on EE and DG as the sole sources of sales changes addressed by the LFCR, and the demand component of the calculation of lost revenue.

[23] TEP states in response to VSI 2.40 that it views distributed generation or DG programs as synonymous with net metering programs but the mechanism is intended to be inclusive of both DG and net metering.

Q. Please describe the concerns you have with respect to the sources of sales effects.

A. As described in the opening section of this testimony, sales can fluctuate up and down for a variety of reasons. A relevant example is the increase in test year sales due to warmer than normal weather described by TEP in its "weather normalization" adjustment. The adjustment reduces test year sales to eliminate the impact of the warmer than normal 2011 summer. However, the cooling degree data provided by TEP in response to VSI 2.55 appears to show 2011 as part of a long-term trend, and not an aberration.



As noted by TEP witness Jones on page 9 of his direct testimony, the weather normalization adjustment is a negative $7,573,805, translating to an *increase* in revenue requirements of about $12 million, after grossing up for income taxes. In other words, had 2011 weather been equal to the ten year trend, electricity sales would have been lower. This adjustment finds that the additional sales resulting from non-normal weather is the same order of magnitude as the cumulative sales effects of energy efficiency programs and DG programs for which TEP seeks recovery of lost revenue.

Q. Are you taking issue with the determination of inclusion of the weather normalization adjustment?

A. Not at all. I am suggesting that other conditions can affect sales as much as those for which TEP seeks to account. We simply don't know what the weather will be in the future, and time will tell how much "more extreme than normal" the weather in 2011 actually was, but cooling degree data appears to show a trend. This uncertainty can be addressed by inclusion of a weather normalization sales adjustment in the LFCR mechanism. Note that weather normalization sales adjustments can work in both directions – adding sales in cooler than normal years or reducing sales in warmer ones.

Q. In addition to the weather normalization issue you previously discussed, do you have any concerns about the mechanics of the LFCR mechanism?

A. Yes, I do have a concern about one additional element of the LFCR. In a nutshell, the LFCR tries to isolate the rate component for each applicable rate class that recovers the utility's fixed costs. For example, TEP's view is that all costs recovered through the residential rate class energy charge are fixed, since it proposes to move fuel costs fully into the PPFAC mechanism. Thus TEP believes the revenue associated with every kWh of residential sales reduction related to EE or DG represents a loss to fixed cost recovery. Given TEP's assumptions about fixed and variable costs, I don't disagree with this perspective.

However, the rates for larger customers that include a demand charge are treated somewhat differently. Because the demand charge for these classes recovers the assigned fixed costs, a loss in fixed cost recovery only occurs if there is some reduction to the demand-based revenues that the commercial solar customer (or commercial energy efficiency program participant) provides. For example, if the commercial customer generally experiences its peak demand at night, then there would be no loss in fixed cost recovery related to the solar system. If the commercial solar customer's peak occurs each day coincident with the solar generation peak and there is never any cloud cover at that time, then the customer's demand revenue will be reduced. Since commercial customers are not homogeneous and the degree to which a DG solar system will offset demand charges will vary greatly, an assumption must be made regarding how much the demand charge is reduced for every kW installed, and in turn for every kWh of sales reduction, for commercial solar customers.

Q. Has TEP made such an assumption?

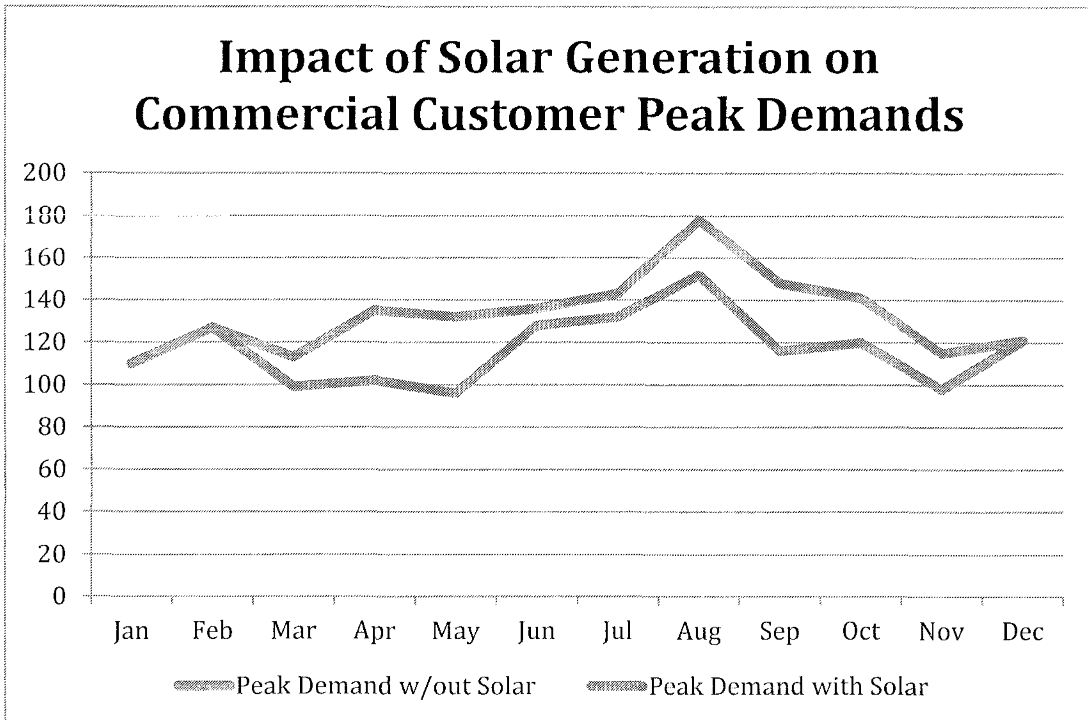
A. Yes. The LFCR mechanism implicitly assumes that half (50%) of the demand-based revenues will not be recovered from commercial customers with solar generation, and proposes to recover these revenues through the mechanism. However, there is no analysis or supporting evidentiary material to back this amount up. Indeed, TEP explicitly said that it does not believe that EE and DG programs reduce individual customer peak demands by one-half.[24]

Q. Does 50% seem like a reasonable figure?

A. No, it doesn't. The proper way to determine any demand charge-related revenue reduction associated with DG or EE programs is to analyze a representative sampling of such customers over an extended period of time. To my knowledge this has not been performed by any Arizona utility. The only Arizona-specific information of which I'm aware is a recent summary report addressing net metering submitted to the Commission on December 6, 2012 by Arizona Public Service in its Renewable Energy Standard (Docket Nos. E-01345A-10-0394 and E-01345A-12-0290). While it is a hypothetical example, Table 10 in Appendix B delineates the demand charge reductions for a commercial customer assuming a solar installation that matches its peak load of 178 kW.

[24] Response to VSI 2.49

Month	Peak kW Demand w/out Solar	Peak kW Demand with Solar	Solar Impact on Peak - kW	% of Solar System Size
Jan	110	110	0	0%
Feb	127	127	0	0%
Mar	113	99	14	8%
Apr	135	102	33	19%
May	132	96	36	20%
Jun	136	128	8	4%
Jul	143	132	11	6%
Aug	178	152	26	15%
Sep	148	116	32	18%
Oct	141	120	21	12%
Nov	115	98	17	10%
Dec	121	121	0	0%
		Average kW Reduction	**16.5**	**9%**



The results show that on average demand charges would be reduced by only 9% of the capacity of the on-site solar generation. Thus, the 50% assumption proposed by TEP appears to be vastly overstated and should not go into effect.

Q. Are there fuel cost savings realized by all customers?

A. Yes. As fuel is a cost passed directly through to consumers, savings related to fuel costs will inure to the benefit of all customers frequently - whenever the PPFAC is updated. Moreover, as generation is typically dispatched on an economic basis, a kWh saved by a retail customer reduces marginal generation requirements by some 1.1kWh, accounting for losses. Marginal generation costs typically are burning the most expensive fuel of all resources on line. Thus, depending on the fuel mix, the savings generated by the sales reduction is often 10-40% higher than the average cost of fuel.

Q. Do you have other comments regarding the LFCR?

A. Yes. It is important to acknowledge that there are costs other than fuel that are avoided as a result of energy efficiency and distributed generation programs. The LFCR mechanism only addresses the revenue side of the equation related to non-fuel costs.

Q. Are you suggesting that there are fixed costs in TEP's cost of service soon to be embedded in rates that are avoided by the EE and DG programs?

A. No. The test year costs are for the most part sunk and cannot be "put back in the bottle." However, as TEP itself notes, "DSM programs will reduce TEP's annual energy requirements by approximately 1,700 GWh in 2020, scaling back that year's system peak demand by 325 MW. But for those programs, TEP would be evaluating the need for another new power plant or finding another source for that energy."[25] The savings to customers are not insignificant – about $430 million in capital costs including the transmission interconnection.[26]

Additionally, there have been a number of recent studies that have found avoided cost benefits related to DG. A review of several studies was conducted by the Solar America Board for Codes and Standards[27] in a report entitled "A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering" released early in 2012. The report reviews and synthesizes three studies performed for major utilities in Arizona, California, and Texas. While the analysis and results of the studies are utility specific, the methodology can be generalized and inform reviews of benefits and costs of distributed solar resources elsewhere. The report suggests the following benefits are provided by DG:

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[25] Direct testimony of TEP witness Bonavia, page 14.
[26] Response to VSI 1.16.
[27] See http://www.solarabcs.org/current-issues/interconnection.html

Benefits to the Utility
Avoided Energy Purchases (inc/fuel)
Avoided T&D line losses
Avoided Capacity Purchases
Avoided T&D Investments and O&M
Environmental Benefits – NO_x, SO_x, PM, & CO_2
Natural Gas Market Price Impacts
Avoided RPS Generation Purchases
Reliability Benefits

Q. Are these benefits available to the utility immediately upon deployment of distributed generation?

A Yes. The benefits exist as soon as the DG is installed and operating, however some of the costs will not be immediately avoided. For example, there are capacity benefits that exist right away, but actual cost savings such as those identified by TEP related to DSM, may not be realized until a new plant is actually avoided. It is possible however that such capacity benefits could be realized much sooner if there are purchased capacity costs that can be avoided.

Q. How significant is the capacity benefit provided by solar resources in Arizona?

A. There are two steps to determining the capacity benefits. First is determining how much of the solar capacity can be relied upon to help the utility meet its system peak. The second step incorporates the current capacity situation of the utility and how the available solar capacity can impact its resource plan. There is some information available on the former issue, however I have not engaged in the

TEP resource planning process and cannot take a position with respect to the opportunities for utility capacity cost reductions, other than relying upon the testimony of Mr. Bonavia.

With respect to the determination of the portion of solar capacity that can be counted upon for meeting utility system peak loads, the National Renewable Energy Laboratory released a report[28] in June 2006, reviewing effective load carrying capability (ELCC) analyses and estimating statewide ELCCs for each state. The report includes a comparison of the results of solar capacity analyses performed in the early 90s with similar studies performed in the 2002-03 time frame that include additional data. Tucson Electric Power, Arizona Public Service and Salt River Project are three of the 39 utilities reviewed. All three Arizona utilities were found to have ELCCs for a two axis tracking solar resource (with low penetration) of about 70%. The report also estimated statewide ELCC results for Arizona assuming several penetration levels for several different solar resource configurations, two of which are repeated here:

Installation Geometry	Capacity Value at 2% Penetration	Capacity Value at 5% Penetration
2-axis Tracking	71%	68%
Horizontal	55%	52%
South 30° tilt	57%	54%
Southwest 30° tilt	65%	61%

[28] Perez, Margolis, et al., *Update: Effective Load-Carrying Capability of Photovoltaics in the United States*, Conference Paper NREL/CP-620-40068, June 2006.

Note that increasing penetration levels of solar resources reduce the capacity value as the system peak load is shifted later in the day. This chart indicates in all cases that at least half of the solar capacity installed can reliably contribute to the capacity needed by the utilities to serve peak loads. This significant value for solar resources is provided to the grid by virtue of the installations and all customers will receive these benefits over time as they impact the resource planning of the utility.

The takeaway point is that solar contributes value and even the potential for fixed cost reduction. These solar values will offset additional costs that are being recovered from non-participants in the solar programs.

Q. Please summarize your recommendations regarding the LFCR?

A. The non-fuel benefits generated by distributed solar will accrue over time to all ratepayers of the utility. However calculating some of these benefits can be complex and is not without controversy. Thus in my view, TEP's LFCR approach provides a reasonable balance of interests and administrative efficiency. That said, there are two changes to the mechanism that should be made:

1. Include an adjustment to account for "non-normal" weather related sales, based on cooling degree days; and

2. Either eliminate the adjustment for demand charge revenue impacts altogether, or include an appropriate level of demand charge revenue impact based upon a thorough analysis of a representative sampling of such customers over an extended period of time.

Q. Do you have any other comments related to this issue?

A. Yes. The recommendation I have just outlined is sufficient to capture the revenue effects of sales changes largely out of the control of TEP. However, as noted at the beginning of this testimony, the impacts of economic conditions can far outweigh the effects of efficiency and solar programs, and weather combined. As such, Vote Solar would also find a full decoupling approach acceptable, provided the demand charge matter herein discussed is properly addressed.

Q. Please summarize your recommendations in this proceeding.

A. Utilities across the country including TEP have experienced major changes and shifts in the historically stable business. As a result utilities are seeking incremental changes in certain aspects of their business model. In this proceeding, TEP is proposing a number of structural changes to its retail rates in an effort reduce the uncertainty and improve the stability of revenue recovery related to electric sales. In this testimony I have addressed three of those changes.

1. Customer Charges: I recommend that TEP's proposed change to the Customer Charges as submitted be rejected in this proceeding. However, TEP should submit support for specific costs to be recovered through the customer charge, and a limited stakeholder process should ensue to reach accommodation.
2. Demand Ratchet: I recommend the Commission reject this proposal in its entirety for the reasons described above.
3. Lost Fixed Cost Recovery: With the two changes below, TEP's LFCR approach provides a reasonable balance of interests and administrative efficiency.
   a) Adjust sales to account for "non-normal" weather; and
   b) Eliminate the adjustment for demand charge revenue impacts. In the alternative, include an appropriate level of demand charge revenue impact based upon a thorough analysis of a representative sampling of such customers over an extended period of time.

Finally, as an alternative to the TEP proposed LFCR mechanism, a full decoupling approach could be considered, and would have our support.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Rick Gilliam

January 2012 to Present: Director of Research and Analysis, the Vote Solar Initiative, San Francisco, CA. Manages the technical and policy research for Vote Solar, and engages in state, regional, and national campaigns related to key solar market policies.

January 2007 to January 2012: Vice President, Government Affairs, Sun Edison, LLC, Beltsville, MD. Directs and manages policy development and implementation for the Americas at the regulatory and legislative levels. (Promoted from *Managing Director* June '09 and from *Director* Sept '07)

Dec 1994 to Jan 2007: Senior Energy Policy Advisor, Western Resource Advocates (formerly the Land and Water Fund of the Rockies), Boulder, Colorado. Develop innovative clean energy and air quality public policies within the economic and cultural framework unique to this region. Lead environmental advocate in development of Arizona Environmental Portfolio Standard, Nevada Renewable Portfolio Standard implementation rules, Colorado Renewable Energy Standard legislative proposals, and the 2003 Utah Renewable Energy Standard legislative proposal. Principal author of Colorado's Amendment 37 and lead advocate for related PUC rule development.

Jan 1983 to Dec 1994: Director of Revenue Requirements, Public Service Company of Colorado, Denver, Colorado. Primary responsibility for development of formal rate-related filings for this investor-owned utility for electric, gas, and thermal energy service in two states and the FERC. Developed and responded to a variety of proposed mechanisms to encourage the use of energy efficiency technologies, including innovative rate design approaches.

Dec 1976 to Dec 1982: Technical Witness (Engineer), Federal Energy Regulatory Commission, Washington, D.C. Testified as expert witness on behalf of the FERC in wholesale rate filings on technical, accounting, and economic issues related to rate design, pricing, and other issues.

A. Education

Masters, Environmental Policy and Management, University of Denver, Denver, Colorado

Bachelor of Science, Electrical Engineering, Rensselaer Polytechnic Institute, Troy, New York

B. Related Publications

Gilliam and Baker, "Green Power to the People," *Solar Today*, July/August 2006.

Dalton & Gilliam, "Walking on Sunshine: Energy Independence on the Rez," *Orion Afield*, Summer, 2002.

Gilliam, Rick, "Revisiting the Winning of the West," *Bulletin of Science, Technology & Society*, April 2002.

Blank, Gilliam, and Wellinghoff, "Breaking Up Is Not So Hard To Do: A Disaggregation Proposal," *The Electricity Journal*, May 1996.

Summary of Formal Testimonies available upon request

BEFORE THE ARIZONA CORPORATION COMMISSIO

EXHIBIT

VoteSolar -2

ADMITTED

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

TESTIMONY OF RICK GILLIAM IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT ON BEHALF OF THE VOTE SOLAR INITIATIVE

FEBRUARY 15, 2013

Introduction

Q. Please state your name and business address.

A. My name is Rick Gilliam. My business address is 1120 Pearl Street, Suite 200 in Boulder, Colorado.

Q. Are you the same Rick Gilliam that has previously filed testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide Vote Solar's rationale for its support of the proposed settlement agreement in this proceeding.

Q. Please summarize your testimony.

A. TEP made a number of proposals in its initial filing in this docket related to cost allocation and recovery mechanisms with which Vote Solar raised a number of concerns. These proposed structural changes were intended to reduce the uncertainty and improve the stability of retail revenue recovery. My direct testimony addressed three of those changes that would affect DG solar customers: the proposed increase to the monthly customer charges; the proposed increase in the demand ratchet for certain customer classes to 100%; and the Lost Fixed Cost Recovery Mechanism.

The proposed agreement addresses each of these elements in a way that Vote Solar accepts and supports for the purposes of settlement.

Q. Please summarize Vote Solar's recommendations in its initial testimony in this proceeding.

A. My recommendations in my direct testimony included the following:

1. Customer Charges: While I recommended that TEP's proposed changes to Customer Charges as submitted be rejected in this proceeding, I also suggested that TEP should provide cost justification for its proposed changes.
2. Demand Ratchet: I recommended this proposal be rejected in its entirety based on (1) inconsistency with cost causation and rate design principles, (2) the creation of a new, maximized cross subsidy within the applicable rate classes, (3) exacerbation of the existing disparity between demands used for allocation and those used for billing, and (4) increasing the disincentive for customers to invest in technologies that can reduce demand.

3. Lost Fixed Cost Recovery: I proposed that TEP's LFCR approach would provide a reasonable balance of interests and administrative efficiency if sales were also adjusted to account for "non-normal" weather, and the adjustment for demand charge revenue impacts was eliminated due to lack of support. In the alternative, I suggested that an appropriate level of demand charge revenue impact could be included based upon a thorough analysis of a representative sampling of such (demand/energy) customers over an extended period of time. Finally, as an alternative to the TEP proposed LFCR mechanism, I indicated a full decoupling approach would have our support.

Q. How did the proposed settlement agreement address Vote Solar's concerns?

A. The proposed agreement addressed our concerns as follows:

1. Customer Charges: TEP's original proposal for increased monthly customer charges has been reduced by nearly half. While I still believe that electric rate components should be cost-justified, this small increase in the customer charge will have minimal impact on net-metered customers. I encourage the Commission, its staff, and others to seek a cost basis for future changes of this nature.
2. Demand Ratchet: Here too, the proposed settlement agreement roughly cuts in half the proposed increase in the demand ratchet. While as a

matter of principle I don't believe ratchets in general are consistent with cost causation and rate design principles, the ratchet should have little effect on commercial customers who install solar behind their meter.

3. LFCR: Of the two adjustments I had proposed to the LFCR mechanism, the sales adjustment for weather was excluded from the proposed settlement. While I felt that this would have had a mitigating effect on the sales reductions TEP is attempting to capture through the LFCR, it was less important to Vote Solar than the adjustment to account for reductions in demand-related revenues. The POA for the LFCR appeared to assume that half of the demand revenues of net-metered customers would be lost due to the solar generation. The proposed settlement includes new language in the POA that clarifies that the actual metered billing demand reduction at the time of the customer's peak will be the basis of the lost demand revenue. This is logical and consistent with the lost revenue concept TEP is seeking to address with this mechanism.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Zwick-1

BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA

DOCKET No. E-01933A-12-0291

NOTICE OF FILING DIRECT TESTIMONY OF CYNTHIA ZWICK, CHARLES COLLINS AND MALISSA BUZAN

I hereby provide notice of filing the direct testimony of Cynthia Zwick, Charles Collins and Malissa Buzan on behalf of Cynthia Zwick.

RESPECTFULLY SUBMITTED THIS 11TH DAY OF JANUARY, 2013.

By: ____________________
Cynthia Zwick
1940 E Luke Avenue
Phoenix, AZ 885016

EXHIBIT
Zwick-1
ADMITTED

ORIGINAL and 13 copies filed with the
Arizona Corporation Commission and copy of the
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BEFORE THE ARIZONA CORPORATION COMMISSION

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SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET No. E-01933A-12-0291

Direct Testimony of

Cynthia Zwick

January 10, 2013

Q. Please state your name and address.

A. My name is Cynthia Zwick and my address is 1940 E. Luke Avenue, Phoenix, Arizona, 85016.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to ask the Commission to:

1) Deny the proposed Lifeline Rate modification;

2) Continue to exclude the Lifeline customers from the DSMS charge;

3) Continue to allow qualified and enrolled Lifeline customers to maintain their eligibility and rate if they move residence while a TEP customer; and

4) Approve an alternative means of investing and using the LIFE fund to more effectively serve the low-income customers it was originally intended to serve and support.

I recognize that the Company is also recommending that all Lifeline customers become subject to an annual recertification of eligibility, and while I believe this will actually increase costs to the Company, I don't oppose this move.

Q. What is your experience with low-income issues and with rate proceedings in Arizona?

A. I have served as a low-income advocate in Arizona since 2003, and have participated in rate cases since that time in order to ensure that the interests and impact of rate increases on the low-income community are heard and understood, and that there is a better understanding of the condition of poverty in Arizona and its impact on utility customers.

Q. What is the current state of poverty in Arizona today?

A. Let me start by stating that I absolutely support a healthy electric utility and believe that rates that are reasonable and affordable for all customers, including low-income customers, is not only in the customers' best interest, but also in the Company's best interest.

I'd like to place this response in the context that was set by both Mr. Bonavia and Mr. Hutchens in their testimony. On page 6 of his testimony, Mr. Bonavia states that, "The downturn in Arizona's housing market and the increase in the unemployment rate combined to slow the traditional growth of TEP's retail customer base." On page 7 of Mr. Hutchens' testimony, he states "We also understand that our local community is trying to recover from a weak economy." Mr. DesLauriers states on page 10 of his testimony, "During this time, economic activity slowed dramatically and economic conditions continue to be weak." These two Company executives and consultant acknowledge the negative impact the economy has had on their customers' ability to purchase and use electricity. The greater Tucson area and Pima County are not only struggling to recover, the families in these areas are falling further and further behind.

In 2010, the US Census bureau reported that the Pima County poverty rate was 16.4% (the state of Arizona was 15.3%).[1] In 2011, the City of Tucson climbed into the top 10 cities for a high poverty rate tied at number 5, reaching

[1] U.S. Census Bureau, 2010 American Community Survey

20.4%. Looking at the 2010 data, 21.3% of Tucson residents live at 100% of the federal poverty level, and in South Tucson, the number jumps to 53.6%.[2]

The annual income for an individual living at 100% of the federal poverty level is $11,170. For a family of four, that annual income is $23,050. An individual living at 150% of the federal poverty level earns $16,755 annually and a family of four, $34,575.

The low-income programs sponsored by the Company, the Lifeline discount and the LIFE fund, set eligibility for customers at 150% of the federal poverty rate. There are 34.3% of Tucsonans living at 150% of the FPL, and in South Tucson, 69.1% of the population live at 150% of the FPL. The rate for Tucsonans and those living in Pima County is significantly higher than the state percentage of 25.3%.[3]

In November 2012, the Arizona unemployment rate was 7.8%, down from the October rate of 8.1% but still high. The highest level Arizona saw was in November 2009, when unemployment reached 10.8%. [4] The Bureau of Labor Statistics announced in August 2012, that in January 2012, 56 percent of the 6.1 million long-tenured displaced workers were re-employed (long-tenured are employees who have worked for their employers three or more years).[5] Among those long-tenured workers who were displaced from full-time wage and salary jobs and who were re-employed in such jobs in January 2012, only 46 % of the re-

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[2] Ibid
[3] Ibid
[4] www.deptofnumbers.com/unemployment/arizona/
[5] www.bls.gov/news.release/disp.nr0.htm

employed 56% had earnings that were as much or greater than those of their lost job. So unemployment remains high, and those re-employed are not making as much as they were before the recession and the various job losses.

Hunger also continues to challenge families in Arizona, children in particular -- 25% are hungry. Approximately 1 in 5 Arizonans, (20.5%) have experienced times in the past twelve months when they did not have enough money to buy food that they or their families needed.[6] Arizona ranked 15th nationally for the number of families facing food hardship. SNAP (formerly known as food stamps) enrollment has also continued to climb in Arizona where now 1.1 million Arizonans need SNAP to feed themselves and their children. 18% of Tucsonans don't have enough to eat.

Q. Are there other factors that need to be taken into consideration when considering the TEP rate increase?

A. Yes, there are. Additional factors to consider include the very real health risks associated with an inability to maintain electric service. In a report by the Arizona Department of Health Services[7], lack of air conditioning can be a life threatening condition in Arizona. Between 1992 and 2009, 173 Arizona residents died from exposure to heat while indoors, two-thirds of whom were 65 or older.

The AARP study, "Affordable Home Energy and Health: Making the

[6] Food Research and Action Center (FRAC), Food Hardship in America 2011, February 2012.
[7] Arizona Department of Health Services, Deaths From Exposure to Excessive Natural Heat Occurring in Arizona 1992-2009, www.azdhs.state.az.us.

Connections," [8] finds that "Health is at risk *directly* through exposure when heat is turned down in winter or air-conditioning is turned off in summer, when unsafe means are used to heat or light homes, and when utility service is lost due to nonpayment."

- In response to high home energy prices perceived as unaffordable, 46% report closing off part of their home for at least one month a year, 24% maintain their home at what they perceived as an unsafe or unhealthy temperature and 17% report leaving their home for part of the day because they were unable to maintain moderate indoor temperatures.
- More than one-quarter (27%) report using the kitchen stove or oven for heat, and 4% use candles or lanterns because of loss of utility service for non-payment.
- More than one-quarter (28%) report skipping payments of a utility bill or paying less than the full amount, 19% received a shut-off notice within the past year, and 6% report the loss of either electrical or natural gas service for nonpayment.
- One in six (17%) report that they were unable to use their main heating source at some point during the previous year because they did not have the money to accomplish one or more of the following: fix or replace a broken furnace; purchase bulk fuel such as heating oil, propane or wood; or

[8] AARP Public Policy Institute, "Affordable Home Energy and Health: Making the Connections," Lynne Page Snyder, PhD, MPH and Christopher A. Baker, June 2010, pp. 18-20.

prevent the shutoff of utility service for nonpayment.

- One in eight (12%) report that they were unable to use their air-conditioning at some point during the previous year because they did not have the money to accomplish one or both of the following: fix or replace a broken air conditioner; or prevent the shutoff of electricity for nonpayment.

The National Energy Assistance Directors' Association conducted a survey in April of 2009 of Low Income Home Energy Assistance Program (LIHEAP) recipients and reports the following:[9]

- LIHEAP recipient households are likely to be vulnerable to temperature extremes;
- 39% of the homes had a senior in the household aged 60 or older;
- 44% had a disabled household member;
- 45% had a child 18 or younger;
- 92% had a least one vulnerable household member.

The study also provided information on challenges that these households faced:

- 36% were unemployed at some point during the previous year;
- 82% had a serious medical condition;
- 25% used medical equipment that requires electricity

The NEADA sturdy further reports indirect threats to health imposed by

[9] National Energy Association Directors' Association, 2009 National Energy Assistance Survey, Final Report, April 2009, www.neada.org

financial stress when various demands compete for their limited dollars include:

- 30% report going without food for a least one day because of energy bills in the past five years.
- 41% report going without medical or dental care
- 31% did not fill a medical prescription or took less than a full dose because of high energy bills. And finally,
- 25% had someone in the home become sick because the home was too cold.

In Arizona in State Fiscal Year 2011, Community Action Agencies served a total of 205,702 individuals and 67,080 families. Of the households served, 71,082 sought help with their utility bills, and 60,738 received utility assistance.[10] Agencies were able to serve on average, 1 in 10 of the eligible people seeking assistance.

Q. Why are you opposing the modification to the Lifeline rates as proposed by the Company?

A. As I believe is clear from the information provided above, TEP customers are extremely vulnerable and have not yet begun to fully recover from the recession that began in 2007. As I've pointed out, more families are falling into poverty than ever before.

That said, according to Mr. Jones' testimony there are currently approximately 23,000 Lifeline customers. While the reasonable rate increase the Company is proposing in this case averages 15.3%, the Lifeline customers are seeing increases of 9.7% to 67.4%. There is nothing just or reasonable in this proposal for low-income

[10] NASCSP Arizona CSBG IS 2010 Report.

customers. Customers who are currently enrolled in frozen rates, or who have been served through these frozen rates for many years, are still eligible, which means that their financial situation has not improved, and they are struggling like those described above. Not only are they unable to pay their bills today and pay all other necessary bills, they cannot pay 67% more. It is completely unacceptable to charge low-income customers a higher percentage increase than any other class of customers.

While I understand the Company wants to reduce the number of rates available and make the rate selection process more efficient for staff and easier to navigate for customers, the fact that there is no proposal contained in this rate case to ease the impact for these customers is shocking and unacceptable. Based on the simple facts of the current economy and environment, I ask that the Commission hold these customers harmless in this case.

Q. Why are you opposing the inclusion of the Lifeline customers in the DSMS charge?

A. The DSMS charge is a relevant charge for those customers who are able to take advantage of the various energy efficiency programs offered by TEP. As reflected earlier in my testimony, unfortunately the Lifeline customers are unable to access most of the energy efficiency programs as they simply don't have the financial means to do so. If a customer is income qualified, has the appropriate housing unit and can gain access to the weatherization program and services offered in their community, they may be able to take advantage of the weatherization program, the only program viable for a low-income household.

For those low-income customers interested in conserving energy in their homes, it is a much more difficult task as the quality of the housing stock in which these families live is poor, and low-income families spend a greater percentage of their incomes on energy services due to poor insulation, inefficient or non-functioning HVAC systems and appliances, and the simple reality of having lower incomes.

I am, therefore, asking the Commission to maintain the DSMS charge exemption for Lifeline customers.

Q. What is your recommendation for the mobility of the Lifeline rate?

A. In Mr. Jones' testimony on page 72 he states, "if a customer has an income level that qualifies them for a discount and they move, they should re-qualify for the open Lifeline rate or no longer be able to participate. Ultimately, all "frozen rates" should be eliminated which would remove any need for a rate to be mobile."

I am unclear what thawing the frozen rates has on the issue of mobility, or what the benefit is to the Company for requiring the requalification, other than the potential to drop more customers from this rate.

In a paper entitled, "Residential Mobility and Youth Well-Being: Research, Policy and Practice," the authors state that, "the United States has been described as a nation of movers with 15-20% of its population relocating each year. The vast majority of these citizens – renters in households earning less than $25,000 per year – are economically disadvantaged both by tenure and by income."[11]

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[11] Residential Mobility and Youth Well-Being: Research, Policy and Practice," Scanlon, Edward, Devine, Kevin, Journal of Sociology and Social Welfare, March, 2001, Volume XXVIII, Number 1, p 119.

If a Lifeline customer is qualified and enrolled, and they move – as low income individuals often do – they should be able to stay enrolled in the discount program until such time as they notify the Company of a change in circumstances, ideally more income being realized by the family, or are required to re-verify their household income during the annual re-verification cycle proposed in this case. There is simply no good reason to punish them by dropping them or requiring they reapply for a rate they've previously been determined eligible to receive.

Q. What is TEP proposing for the LIFE fund?

A. The LIFE fund was established in Decision 59594 with the purpose stated "to assist low income individuals and individuals with severe financial emergencies who are not eligible for assistance through other programs or who cannot be served by State/Federal programs due to lack of funding, subject to the following conditions.

a. TEP will establish a separate account with a principal balance of $4.5 million. The interest earnings thereon will be used to fund the LIFE fund. The amount of principal in the account (excluding interest thereon) will not be changed without further order of the Commission.

b. TEP will establish reasonable criteria, subject to Staff review and approval, to qualify individuals for assistance from the fund.

c. In future ratemaking proceedings, the principal balance of the fund (excluding interest thereon) will not be made a part of the rate base.

d. TEP will refer Lifeline customers, who exceed the maximum kWh usage during winter or summer peak periods, to the weatherization program.

e. TEP will continue the weatherization program to expend the full allocated budget, extending the length of the program as needed.

f. TEP will commit to aggressive marketing of time of use and other low income programs.

g. TEP will work with other utilities and ACAA on legislation to establish a state version of a LIFE fund-type program."

In Mr. Jones' testimony on page 82, he indicates that the LIFE fund is currently earning 0.10 percent, which on an annual basis would provide only $4,500 per year in customer assistance. In 2009, 2010 and 2011 the LIFE fund contributed only $9,600, $6,200 and $3,800 respectively to the program. The proposal the Company is making is to now take the $4.5 million originally set aside to assist low-income customers, and use it to pay off short-term debt, and replace those funds with an annual contribution of $100,000 to Arizona Community Action Association (ACAA).

Q. Do you support the Company's proposal for the LIFE Fund?

A. No, I do not.

Q. Do you have an alternative proposal for the LIFE Fund?

A. Yes, I do.

As currently implemented, the $4.5 million is invested and the monthly interest is provided to a community organization in order to serve low income TEP customers. Due to the monthly use of the interest and the interest rates being realized, very few customers are being served.

The lowest payment amount within the LIFE fund used to assist families is $100, and the highest is $306. If we average those numbers, $203, using the level of funding provided by the Company and reflected above, in 2009 approximately 47 TEP customers were served, in 2010 approximately 31 TEP customers were served and in 2011 approximately 19 TEP customers were served. We know that at least 23,000 TEP customers are eligible as they are currently enrolled in the LIFELINE rates, and we may also conclude based on the poverty rate in Tucson, that many more than 23,000 customers are eligible for bill assistance.

My proposal is that the $4.5 million be retained and used as originally intended by the Commission, but that it be provided to ACAA to invest within their Home Energy Assistance Fund program. That fund was established a number of years ago to invest and leverage utility funding in order to serve a greater number of low-income utility customers. By allowing for the use of $100,000 of the original $4.5 million for the first year's service, and the investment of the remaining funding -- $4.4 million -- those funds will be able to generate approximately $100,000 annually and will provide the ability to sustain the support to the community for many years. Charles Collins' testimony will provide the specific structure for the investment strategy. Mr. Collins is with Smith Barney Morgan Stanley, and is the investment advisor for ACAA.

Q. Have you consulted with the leadership of Arizona Community Action Association to ensure this is an arrangement with which they are comfortable?

A. I have. Malissa Buzan, President of Arizona Community Action Association, has provided testimony related to this matter expressing the organization's support of this proposal.

Q. Is there anything you would like to add in conclusion?

A. Yes. As I believe has been articulated in my testimony, an increase such as the one being proposed in this case, is not only unfair, it will devastate families and individuals who are TEP customers, and who struggle every day to literally keep the lights on. I respectfully request the Commission reject the Company's rate request.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
BOB STUMP - CHAIRMAN
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET No. E-01933A-12-0291

Direct Testimony of

Charles Collins

On Behalf of

Cynthia Zwick

January 10, 2013

Q. Please state your name and address.

A. My name is Charles Collins and my business address is 2398 E. Camelback Rd. Ste. 800, Phoenix, Arizona.

Q. By whom are you employed, what is your title and what are your responsibilities?

A. My employer is Morgan Stanley Wealth Management. My title is Senior Portfolio Manager/Vice President. My responsibilities are to provide investment advice and, if a client has granted my team investment discretion, to manage that client's assets at Morgan Stanley. I work on a team with my business partner Dan Marting.

Q. What is investment discretion?

A. Certain clients have filled out paperwork granting us the discretion to make trading decisions on their behalf pursuant to an investment plan approved by the clients.

Q. Please describe your educational background.

A. I graduated from Loras College in Dubuque, Iowa with a degree in Marketing.

Q. Please describe your professional background and experience?

A. I entered the business over 15 years ago with Morgan Stanley and about 8 years ago moved over to Smith Barney.

Q. Have you previously testified before the Arizona Corporation Commission?

A. No.

Q. What is the purpose of your testimony?

A. I have presented to my client the Arizona Community Action Association (ACAA) two proposals to invest $4.5 million in funds currently set aside as the LIFE fund.

Q. Do you currently manage the investment accounts for ACAA?

A. Yes, I do with my co-portfolio manager, Dan Marting.

Q. How long have you managed the ACAA funds?

A. Approximately 4 years.

Q. What are the investment goals for the ACAA?

A. ACAA currently invests its funds to generate returns to fund its services to low-income families.

Q. What have you been asked to accomplish with the investment of the $4.5 million LIFE fund?

A. I was asked to develop two potential investment strategies for ACAA to attempt to generate returns that could be used to serve families in the TEP service territory on an ongoing basis.

Q. What are your recommendations for the investment of the LIFE fund?

A. Per the two attached proposals, we have suggested two alternatives: a conservative model using only fixed income and also a balanced model that contains both fixed-income and equities.

Q. What are the investment goals of the proposed models?

A. The fixed income proposal is designed to generate income; the balanced portfolio proposal would use both equities and fixed income to generate a total return via capital appreciation and income. I would remind you that all investment strategies involve some level of risk. The risk factors are discussed in the proposals themselves, and I refer you to them for more details.

Q. Does this conclude your testimony?

A. Yes.

Attachments to Charles Collins' Testimony

January 8, 2013

Select UMA®

A personalized investment plan for

ACAA

Prepared by:

Marting Collins Group

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Morgan Stanley

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I. INVESTMENT PROFILE

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YOUR INVESTMENT PROFILE

One of the advantages of a consulting relationship is that it provides an objective framework for making investment decisions. This process often includes the development of a personalized, long-term investment strategy.

Consulting Group's four-step investment process is designed to help investors seek to achieve their investment objectives, attain portfolio diversification and reduce risks over time.

- **STEP ONE: Set Investment Objectives**

  Financial Advisors help you to define your investment objectives based on three critical factors: your goals, time horizon and risk tolerance.

- **STEP TWO: Define Investment Strategy**

  Based on your investment objectives, your Financial Advisor recommends an asset allocation strategy designed to provide proper diversification.

- **STEP THREE: Evaluate and Select Investment Products**

  Financial Advisors help you to identify investment products that may be most appropriate given your asset allocation strategy. The investment products may or may not be affiliated with us.

- **STEP FOUR: Ongoing Review Process**

  Financial Advisors consult with you periodically to determine whether short-term or long-term changes are needed in the asset allocation strategy or investment products in your portfolio.

For more information on Consulting Group's Four-Step Process, please speak to your Financial Advisor.

Step 1: Set Investment Objectives

Our discussion of your financial needs and goals was the start of the process that enabled us to learn about you as an investor. Let's review what you told us:

- You will be investing $4,500,000.
- You have selected the FA Discretionary Program.
- You have selected the "custom" version of the asset allocation model.

The following information depicts our understanding of your investment objectives and risk tolerance for your proposed Morgan Stanley Consulting Group Select UMA account.

Please review this information carefully. If you do not agree with this or any other information included in this proposal, please notify your Financial Advisor immediately. Also, please notify your Financial Advisor immediately of any change in the information in this proposal (including any change in your investment objectives or risk tolerance). To the extent that the investment suitability and objectives information noted below conflicts with any other information you communicate to us (e.g., via telephone, e-mail, or Investment Policy Statement), the information contained in this proposal shall control with respect to the management of this account.

I. INVESTMENT PROFILE

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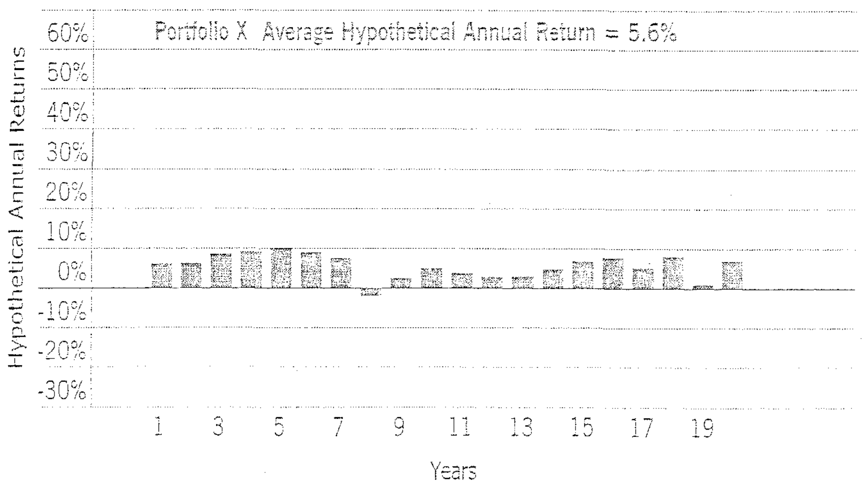
- Your primary purpose for opening this account is to generate current income.
- We understand you need to take regular withdrawals from this account. You will need between 2% and 4% of this account's current value annually.
- For this account, you are primarily concerned with limiting risk. You are willing to accept lower target returns to limit your chance of loss.
- Given your investment goals for this account, you would choose a hypothetical portfolio over a 20-year period similar to the following:



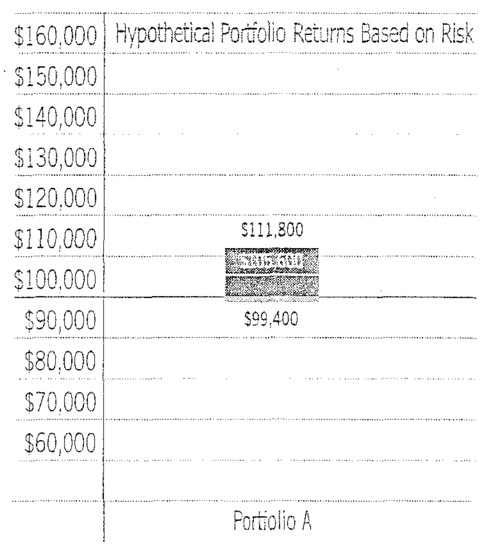
This portfolio is constructed to accept lower annual returns, but also to seek lower risk and volatility. Please note that this is a hypothetical example only, for the purpose of gauging your tolerance for risk. This does not represent any actual historical results and does not include fees or charges that would lower your return. Actual results of any particular account may be less than the "Hypothetical Annual Returns" and "Average Hypothetical Annual Return" shown above, and may be negative.

- The risk of a portfolio suffering a decrease in value (having a negative return) is often a primary concern for investors. In seeking to achieve potentially higher returns, however, an investor must be willing to accept greater risk. Given your investment objective for this account, you would be most comfortable investing this account in a hypothetical portfolio similar to the following:

Portfolio	Hypothetical Value of $100,000 After 1 Year	Hypothetical Chance of Losing Money After 1 Year
Portfolio A	$105,600	3.5%

This portfolio is constructed to accept a lower hypothetical value, but also to seek a lower chance of losing money, after one year. Please note that this is a hypothetical example only, for the purpose of gauging your tolerance for risk. This does not represent any actual historical results and does not include fees or charges that would lower your return. Actual results of any particular account may be less than the "Hypothetical Value" shown above, and may be negative.

- The bar chart below shows a range of hypothetical one-year ending values for a $100,000 initial investment in a portfolio. The hypothetical value of the average return for that portfolio is shown in the center of the bar. Given possible outcomes for various portfolios, you would consider the following hypothetical portfolio to be suitable for you in light of your investment objective for this account:



At the end of a given year, this portfolio has hypothetical ending values between $111,800 (11% return) and $99,400 (negative 1% return). The hypothetical average ending value of this portfolio after one year is approximately $105,600 (6% return). This portfolio is constructed to accept a lower hypothetical average ending value, but also to seek a narrower range of one-year ending values.

It is important to remember that a hypothetical portfolio such as that shown above is more likely to achieve the average return over long-term holding periods. Please note that this is only a hypothetical example, for the purpose of measuring your tolerance for risk. Actual results will vary, and may be worse than the lowest outcome shown on the bar chart above. This bar chart does not represent any actual historical results and does not include fees or charges that would lower your return.

- Inflation can greatly erode the return on your investments, especially over time. For this account, you prefer to minimize short-term fluctuations in portfolio value (and the potential for loss) as much as possible, even if it means that your portfolio has the potential to only keep pace with or slightly exceed inflation (and might not keep up with inflation).

- Sometimes investment losses are permanent, sometimes they are prolonged and sometimes they are short-lived. We understand that if you experienced substantial investment losses in this account, you would sell your investments immediately.

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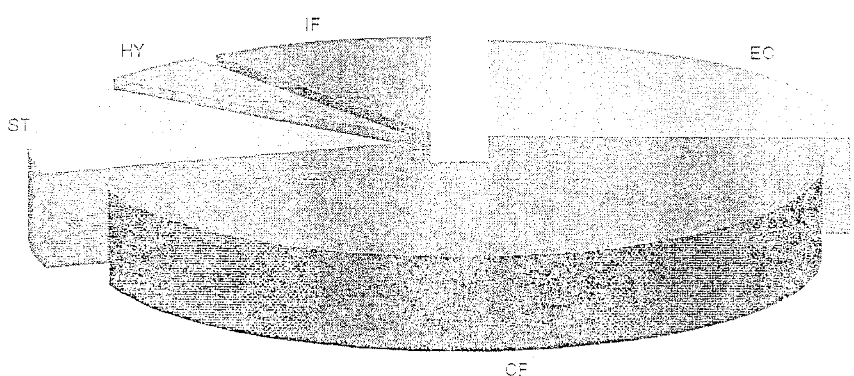
ASSET ALLOCATION

Step 2: Define Investment Strategy

Asset allocation can be one of the most effective investment techniques investors can employ. The appropriate asset allocation policy can provide diversification of your portfolio, lower overall portfolio fluctuation and position your portfolio to take advantage of developing investment opportunities. This is conducted by apportioning your portfolio among different types of investments that may include stocks, bonds, money market instruments and other asset categories. While it is a widely held opinion that diversification is a prudent investment technique, diversification does not ensure against loss.

The following asset allocation is either the asset allocation that we recommend for you based on your investment objectives or a custom allocation that you have selected based on your preferences.



Asset Class	Target
Ultra Short Duration Fixed Inc (EC)	25.00%
US Core Fixed Inc (CF)	45.00%
US Short-Term Fixed Inc (ST)	15.00%
High Yield Fixed Income (HY)	5.00%
International Bonds (IF)	10.00%
Total*	100.00%

*Due to rounding, total may not add to 100.00%.

YOUR PORTFOLIO

Step 3: Evaluate and Select Investment Products

Our Consulting Group Investment Advisor Research department("CG IAR") evaluates most investment products offered in the Select UMA program. CG IAR then reviews these investment products periodically to ensure that they continue to meet Consulting Group's standards. CG IAR does not evaluate investment products affiliated with us (including investment products with "Morgan Stanley," "CGCM," or "GIS" in their names).

In addition, we will monitor the investment products you ultimately select for your portfolio. The purpose of this process is to evaluate whether the investment products selected continue to be compatible with your stated investment objectives and tolerance for risk.

The table below illustrates the percentage of your assets that would be invested in the investment products listed if this proposal is accepted.

Select UMA Custom Model

If "Custom Model" is indicated above, this means that you have selected the Custom version of the asset allocation Model (in which event you (or if you select Financial Advisor Discretion, your Financial Advisor) have selected a customized version of the asset allocation model (instead of utilizing a Model pre-defined and periodically adjusted by Morgan Stanley).

Ultra Short Duration Fixed Inc	Investment Type*	% of Portfolio	Investment Product Benchmark
Pacific Income ST Bond Fd	MF	12.50%	90-Day T-Bills
PIMCO Short Term Bond Fd	MF	12.50%	90-Day T-Bills
Ultra Short Duration Fixed Inc Total		25.00%	

US Core Fixed Inc	Investment Type*	% of Portfolio	Investment Product Benchmark
Blackrock Core Bond	SMA	14.85%	BC Aggregate
PIMCO Total Return Fd	MF	14.85%	BC Aggregate
Western Core Plus Bond Fd	MF	15.30%	BC Aggregate
US Core Fixed Inc Total		45.00%	

US Short-Term Fixed Inc	Investment Type*	% of Portfolio	Investment Product Benchmark
BlackRock Low Duration Fd	MF	15.00%	ML Tsy 1-3 Yr - G1O2
US Short-Term Fixed Inc Total		15.00%	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represents a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

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High Yield Fixed Income	Investment Type*	% of Portfolio	Investment Product Benchmark
Eaton Vance Inc of Boston Fd	MF	2.50%	BC HY
Wells Fargo High Income Fd	MF	2.50%	BC HY
High Yield Fixed Income Total		5.00%	

International Bonds	Investment Type*	% of Portfolio	Investment Product Benchmark
Dreyfus Standish Intl Bd Fd	MF	5.00%	Citi Non-US WGBI Hed
PIMCO Frgn Bd US$ Hedged Fd	MF	5.00%	Citi Non-US WGBI Hed
International Bonds Total		10.00%	
[illegible]		[illegible]	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represents a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

EVALUATION OF INVESTMENT PRODUCTS

In the Select UMA program, we offer a wide range of Investment Products (including Sub-Managers, mutual funds and ETFs) that we have selected and approved. We also offer affiliated investment products, which CG IAR does not evaluate or approve. The remainder of this section ("EVALUATION OF INVESTMENT PRODUCTS"), as well as any references in this proposal to Investment Products being evaluated or approved (or on the "Focus List" or "Approved List") does not apply to affiliated investment products.

Morgan Stanley CG IAR evaluates Investment Products. CG IAR may delegate some or all of its functions to an affiliate or third party. Investment Products may only participate in the Select UMA program if they are on CG IAR's Focus List or Approved List discussed below. The Focus List and Approved List are available at www.morganstanleyindividual.com/accountoptions/managedmoney/manager/default.asp (or you can ask your Financial Advisor for these lists). Only some of the Investment Products may be available in the Select UMA program.

In addition to requiring that Investment Products be on the Focus List or Approved List, we look at other factors in determining which Investment Products we offer in the Select UMA program, including:

- program needs (such as whether we have a sufficient number of Investment Products available in an asset class),
- client demand and
- the Sub-Manager's or Fund's minimum account size.

We automatically terminate Investment Products in the Select UMA program if CG IAR downgrades them to "Not Approved." We may terminate Investment Products from the program for other reasons (e.g., the Investment Product has a low level of assets under management in the program, the Investment Product has limited capacity for further investment, or the Investment Product is not complying with our policies and procedures).

Focus List. To be considered for the Focus List, Investment Products provide CG IAR with relevant documentation on the strategy being evaluated, which may include sample portfolios, asset allocation histories, its Form ADV (the form that investment managers use to register with the SEC), past performance information and marketing literature. For verification purposes, as part of the review process, CG IAR may compare the Sub-Manager's/Fund's reported performance with the performance of a cross-section of actual accounts calculated by CG IAR. CG IAR personnel may also interview the Sub-Manager or Fund and its key personnel, and examine its operations. Following this review process, Investment Products are placed on the Focus List if they meet the required standards for Focus List status.

CG IAR periodically reviews Investment Products on the Focus List. CG IAR considers a broad range of factors (which may include investment performance, staffing, operational issues and financial condition). Among other things, CG IAR personnel interview each Sub-Manager or Fund periodically to discuss these matters. If CG IAR is familiar with a Sub-Manager or Fund following repeated reviews, CG IAR is likely to focus on quantitative analysis and interviews and not require in-person meetings. CG IAR may also review the collective performance of a composite of the Morgan Stanley accounts managed by a Sub-Manager/Fund and compare this performance to overall performance data provided by the Sub-Manager/Fund, and then investigate any material deviations.

Approved List. The process for considering Investment Products for the Approved List is less comprehensive than for the Focus List, and evaluates various qualitative and quantitative factors. These may include personnel depth, turnover and experience; investment process; business and organization characteristics; and investment performance. CG IAR may use an algorithm – a rules-based scoring mechanism – that reviews various qualitative and quantitative factors and ranks each Investment Product in a third party database. (Not all Investment Products reviewed for the Approved List are subject to this algorithm.) CG IAR analysts analyze the information contained in the algorithm to gauge the completeness and consistency of the data which drive the rankings, and then send the Sub-Manager or Fund additional information requests. CG IAR then determines whether the Investment Product meets the standards for Approved List status. Furthermore, CG IAR may evaluate an Investment Product under the evaluation process for the Focus List but then decide to instead put it on the Approved List.

CG IAR periodically evaluates Investment Products on the Approved List to determine whether they continue to meet the Approved List standards.

Changes in Status from Focus List to Approved List. In light of the differing evaluation methodology and standards for the Focus List and Approved List, CG IAR may determine that an Investment Product no longer meets the criteria for the Focus List or will no longer be reviewed under the Focus List review process, but meets the criteria for the Approved List. If so, we generally notify program clients regarding such status changes on a quarterly basis.

Changes in Status to Not Approved. CG IAR may determine that an Investment Product no longer meets the criteria under either evaluation process and, therefore, the Investment Product will no longer be recommended in our investment advisory programs. We notify affected clients of these downgrades. You cannot retain a downgraded Sub-Manager or Fund in your Select UMA account and must select a replacement from the Approved List or Focus List, that is available in the program, if you wish to retain the program's benefits in respect of the affected assets.

In some circumstances, you may be able to retain terminated Investment Products in another advisory program or in a brokerage account, subject to the regular terms and conditions applying to that program or account. Ask your Financial Advisor about these options.

In the Select UMA program, we generally specify a replacement Investment Product for a terminated Investment Product. In selecting the replacement Investment Product, CG IAR generally looks for an Investment Product in the same asset class, and with similar attributes and holdings to the terminated Investment Product. The replacement Investment Product will typically be on the Focus List.

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Watch Policy. CG IAR has a "Watch" policy for Investment Products on the Focus List and Approved List. Watch status indicates that, in reviewing an Investment Product, CG IAR has identified specific areas of the Sub-Manager's or Fund's business that (a) merit further evaluation by CG IAR and (b) may, but are not certain to, result in the Investment Product becoming "Not Approved." Putting an Investment Product on Watch does not signify an actual change in CG IAR opinion nor is it a guarantee that CG IAR will downgrade the Investment Product. The duration of a Watch status depends on how long CG IAR needs to evaluate the Investment Product and for the Investment Product to address any areas of concern. For additional information, ask your Financial Advisor for a copy of CG IAR's Watch Policy.

Tactical Opportunities List. CG IAR also has a Tactical Opportunities List. This consists of certain Investment Products on the Focus List or Approved List recommended for investment at a given time based in part on then-existing tactical opportunities in the market.

III. FEE SCHEDULE

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Morgan Stanley Fee [1]	
$0 - $249,999	0.88000%
$250,000 - $499,999	0.75000%
$500,000 - $999,999	0.75000%
$1,000,000 - $1,999,999	0.63000%
$2,000,000 - $4,999,999	0.63000%
Amount Over $5,000,000	0.63000%

Estimated Total Client Fee Rate [2]	
Morgan Stanley Fee [1]	0.6640%
Sub-Manager Fee	0.0519%
Overlay Manager Fee[3]	0.1200%
Total Effective Rate (%)	[illegible]

[1] If the Financial Advisor Discretion option is chosen, the Morgan Stanley Fee includes an additional charge for FA discretionary services of 25% of Morgan Stanley's basic advisory Fee.

[2] The Estimated Total Client Fee Rate is based on the account asset value shown in the Investment Profile section above, and includes Morgan Stanley, Sub-Manager and Overlay Manager fees, and the asset allocation percentages shown in the Portfolio Strategy Recommendations section above. The actual Total Client Fee Rate may vary depending on the account asset value and asset allocation percentages. From time to time, certain additional fees and charges may apply. For more details, see the Select UMA ADV brochure, available from your Financial Advisor or at www.morganstanley.com/ADV.

[3] Fee compensates the Overlay Manager (which is part of Morgan Stanley) for portfolio rebalancing and other administrative functions.

Please note that performance illustrations used in this proposal do not include the impact of the fees set forth above or any applicable insurance or annuity charges. These expenses will reduce the actual performance of your account. Because the fees are deducted quarterly the fees will have a compounding effect on performance and can be material. For example, for an account with an advisory fee of 2%, if the gross performance is 10%, the compounding effect of the fees will result in a new annual compound rate of return of approximately 7.81%. After a three-year period with an initial investment of $100,000, the total value of the client's portfolio would be approximately $133,100 without the fee and $125,307 with the fee.

Financial Advisors receive as compensation a percentage of the total Morgan Stanley fee you pay. This percentage is the same whether you choose to invest based on one proposal, a blend of several, or your own independent allocation approach, but obviously the dollar amount received will vary based on the effective rate and the amount you choose to allocate to a particular Investment Product. For more details, please refer to the discussion of fees in the Select UMA ADV brochure and your Select UMA Agreement.

Asset Class	Investment Product	Investment Product Type *	Allocation %	Sub-Manager Fee % (SMA Only)
US Core Fixed Inc	Blackrock Core Bond	SMA	14.85%	0.35%
US Core Fixed Inc	PIMCO Total Return Fd	MF	14.85%	
US Core Fixed Inc	Western Core Plus Bond Fd	MF	15.30%	
Ultra Short Duration Fixed Inc	Pacific Income ST Bond Fd	MF	12.50%	
Ultra Short Duration Fixed Inc	PIMCO Short Term Bond Fd	MF	12.50%	
High Yield Fixed Income	Eaton Vance Inc of Boston Fd	MF	2.50%	
High Yield Fixed Income	Wells Fargo High Income Fd	MF	2.50%	
International Fixed Income	Dreyfus Standish Intl Bd Fd	MF	5.00%	
International Fixed Income	PIMCO Frgn Bd US$ Hedged Fd	MF	5.00%	
US Short-Term Fixed Income	BlackRock Low Duration Fd	MF	15.00%	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represent a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

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Mutual Fund & ETF Performance

The performance below shows the average annual total return of each mutual fund/ETF ("Fund") included in the proposal for the periods shown below, as well as since the Fund's inception. To the extent that any of these funds include a sales load, the effect of such a load is reflected in the performance quotations. We are required to illustrate the maximum possible effect of the load by applicable law; however, if you accept this proposal, the funds purchased for you through this program will have such sales loads waived. However, your account will be charged the Select UMA fee, so your returns would differ from – and be lower than – those shown below.

The impact of Select UMA program fees can be material. These program fees are deducted quarterly and have a compounding effect on performance. For example, on an account with a 1% annual fee, if the gross annual performance is 6%, the compounding effect of the fees will result in a net performance of approximately 4.94% after one year, 4.81% after three years and 4.66% after five years. See the Select UMA ADV brochure for an explanation of the fees and charges that would apply if you invest in a Fund through the Select UMA program.

As with any Fund investment, you should consider the investment objectives, risks, charges and expenses of the Funds carefully before investing. Your Financial Advisor is available to discuss these issues in detail with you. Additionally, the prospectus of each Fund contains this information and other information about the Fund. Prospectuses and current performance data are available on our website at www.morganstanley.com or through your Financial Advisor.

The performance data set forth below represents past performance. Past performance does not guarantee future results. Investment returns and principal value of an investment will fluctuate so that an investor's shares may be worth more or less than their original cost upon redemption. Current performance may be lower or higher than the performance data quoted. For Funds with multiple share classes, the data may represent the actual performance of the oldest share class prior to the inception of newer share classes. This data is adjusted to reflect the expenses of the newer share classes.

Performance data as of the most recent month-end may be obtained by contacting your Financial Advisor, calling the fund company at the toll-free number shown in this proposal, or through www.morganstanley.com.

Gross Expense Ratio reflects the annual percentage of a Fund's assets paid out in expenses which include any 12b-1, transfer agent and all other asset-based fees associated with a Fund's daily operations and distribution.

Net Expense Ratio reflects actual expenses paid by a Fund as well as any fee waivers or expense reimbursements, which may be voluntary or mandated by contract for a certain time period. Specific details about expense ratios are outlined in a Fund's prospectus.

* Please see the important performance disclosures located at the end of this Proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

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Average Annual Total Returns as of September 2012

Fund Name	Symbol	Inception Date	1-Year Return	5-Year Return	10-Year Return	Since Inception	Gross Expense Ratio	Net Expense Ratio	Phone Number
BlackRock Low Duration Fd	BFMSX	1992/07	5.43%	3.37%	3.12%	4.54%	0.75%	0.55%	800-441-7762
Eaton Vance Inc of Boston Fd	EIBIX	1972/06	16.48%	7.75%	10.13%	9.09%	0.77%	0.77%	800-262-1122
PIMCO Frgn Bd US$ Hedged Fd	PFBPX	1992/12	11.61%	8.50%	6.51%	7.81%	0.60%	0.60%	888-877-4626
Pacific Income ST Bond Fd	PIASX	1994/04	0.51%	1.85%	2.32%	4.00%	0.39%	0.35%	800-251-1970
PIMCO Short Term Bond Fd	PTSPX	1987/10	3.21%	2.73%	2.96%	4.79%	0.56%	0.55%	888-877-4626
PIMCO Total Return Fd	PTTPX	1987/06	11.39%	8.81%	6.84%	8.24%	0.56%	0.56%	888-877-4626
Dreyfus Standish Intl Bd Fd	SDIFX	1991/01	7.38%	7.64%	6.13%	7.60%	0.76%	0.76%	800-373-9387
Wells Fargo High Income Fd	STHYX	1995/12	17.47%	7.47%	9.47%	7.21%	1.05%	0.94%	800-222-8222
Western Core Plus Bond Fd	WACPX	1998/07	9.26%	8.04%	7.18%	7.04%	0.45%	0.45%	877-721-1926

* Please see the important performance disclosures located at the end of this Proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

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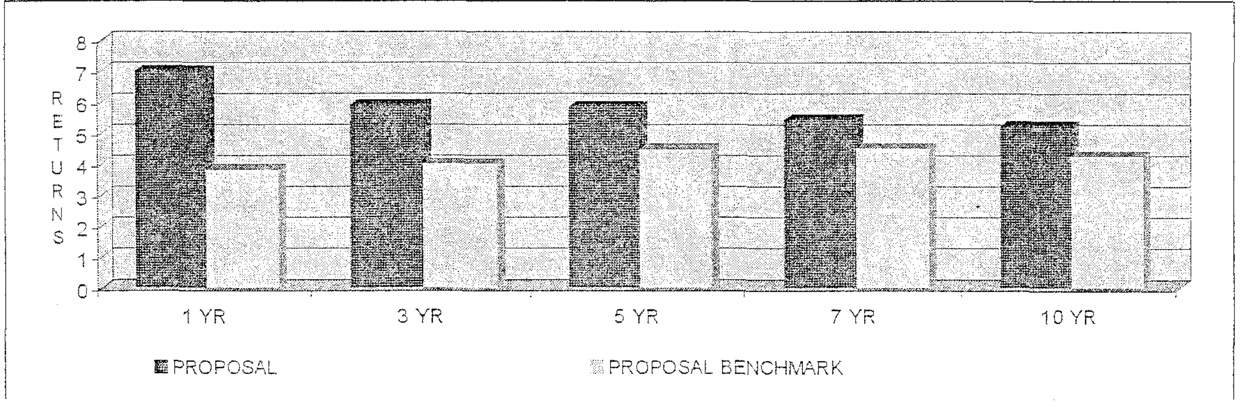
The performance data designated as "Proposal" below on this page **and on each of the following pages of this proposal** is intended to model what the return of a portfolio would have been had you been invested in the investment products recommended in this proposal, in the percentages recommended, over the time periods shown. These returns are hypothetical returns based on a simulated account (not an actual account). You would not necessarily have obtained these performance results if you had held this portfolio for the periods indicated. Actual performance results of accounts vary due to factors such as timing of contributions and withdrawals, and rebalancing schedules. Also, fees would apply to, and reduce the performance of, investment products included in this hypothetical portfolio. **The selection of investment products in this proposal reflects the benefit of hindsight based on historical rates of return. This performance is presented for illustrative purposes only.**

With respect to third-party separately managed accounts ("SMAs"), the performance information is based on other accounts of the investment Sub-Manager that operated with substantially similar investment objectives and policies during the time periods indicated. With respect to affiliated investment products, the performance information is that of the affiliated investment product in a Consulting Group investment advisory program other than Select UMA. The data designated as "Proposal Benchmark" is derived from the stated benchmark of each investment product included in the weightings set forth in our recommendation. As noted above, past performance does not guarantee or predict future results.

It is important to note that the performance set forth below does not take into account the fees that would be charged to the account. As illustrated in the Performance Disclosures at the end of this proposal, if an account had been in existence for the time periods shown, its performance would be lower than that shown by an amount that is directly proportionate to the fee charged. Please see the Fee Schedule for an illustration of the impact of fees on account performance.

PERFORMANCE STATISTICS BEFORE FEES*

Annualized Returns

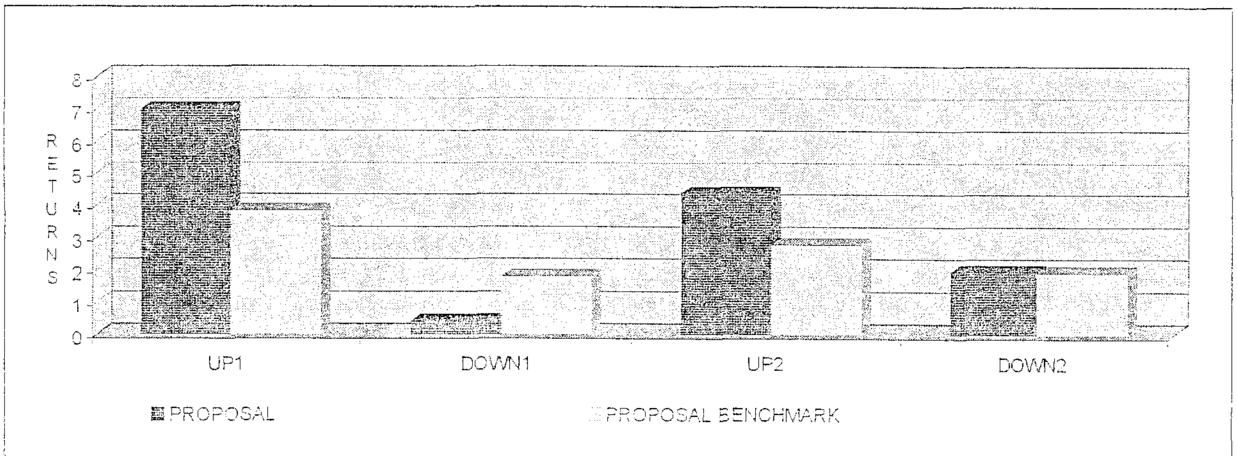


AS OF 09/30/12	1 YR	3 YR	5 YR	7 YR	10 YR
PROPOSAL	6.99%	5.90%	5.83%	5.44%	5.22%
PROPOSAL BENCHMARK	3.82%	4.01%	4.47%	4.51%	4.25%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

Analysis of Up and Down Markets **



	[illegible]	[illegible]	[illegible]	[illegible]
PROPOSAL	6.99%	0.41%	4.38%	1.94%
PROPOSAL BENCHMARK	3.82%	1.79%	2.76%	1.91%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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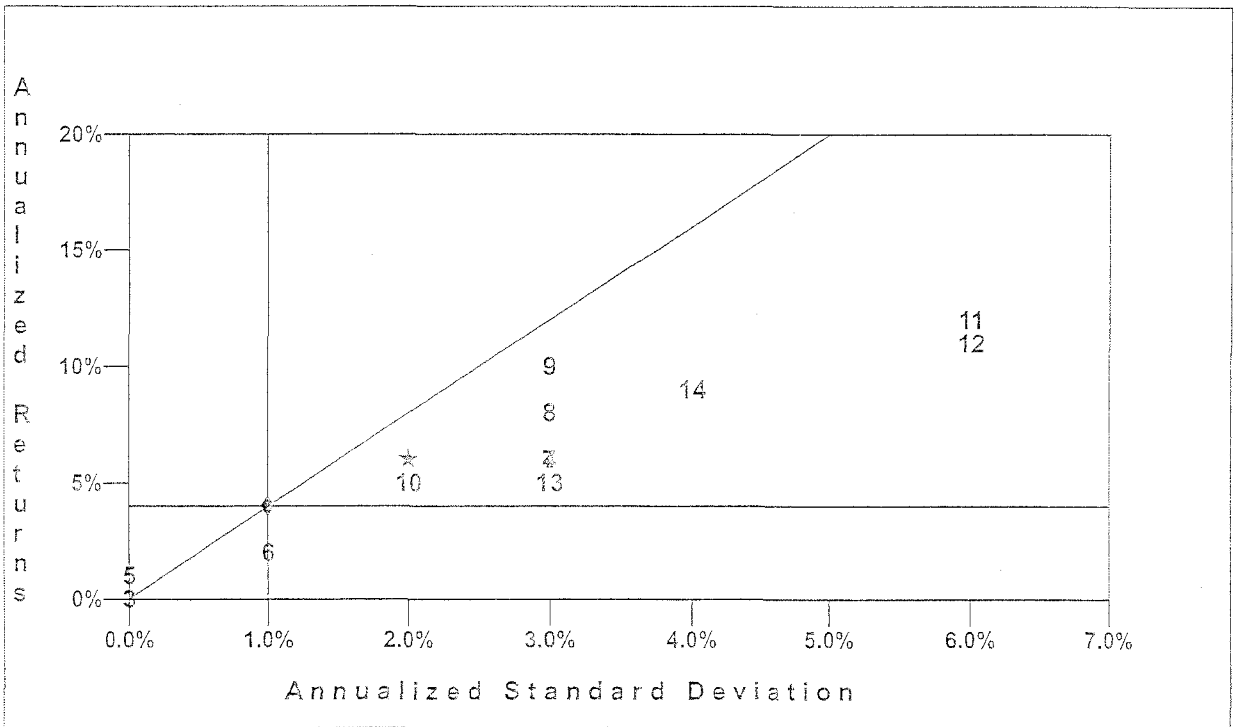
3-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
★ PROPOSAL	5.90%	1.63%
◆ PROPOSAL BENCHMARK	4.01%	1.47%
3 90-DAY TREASURY BILLS	0.09%	0.02%
4 LB AGG BOND INDEX	6.19%	2.93%
5 Pacific Income ST Bond Fd	0.66%	0.31%
6 PIMCO Short Term Bond Fd	1.90%	1.26%
7 Blackrock Core Bond	6.27%	2.82%
8 PIMCO Total Return Fd	7.59%	3.14%
9 Western Core Plus Bond Fd	10.03%	2.58%
10 BlackRock Low Duration Fd	4.63%	1.58%
11 Eaton Vance Inc of Boston Fd	12.20%	6.48%
12 Wells Fargo High Income Fd	11.41%	6.26%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

IV. PERFORMANCE REVIEW*

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AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
13 Dreyfus Standish Intl Bd Fd	5.46%	2.91%
14 PIMCO Frgn Bd US$ Hedged Fd	8.92%	3.56%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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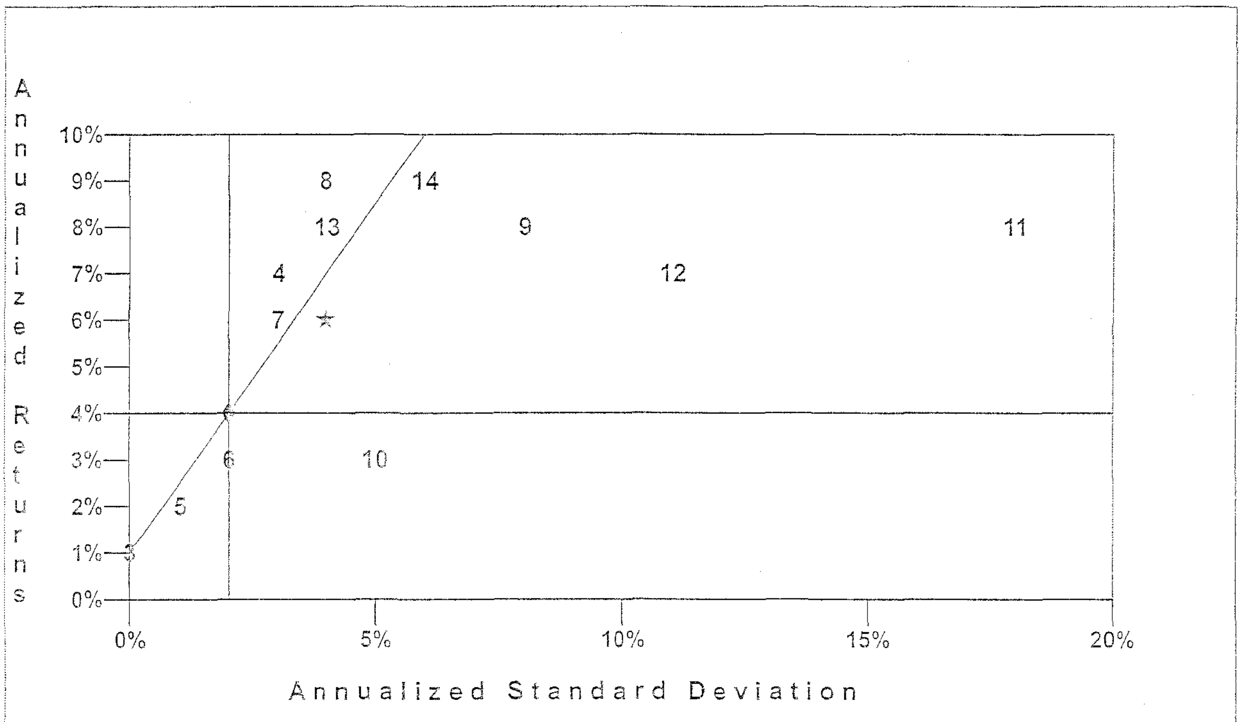
5-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
☆ PROPOSAL	5.83%	3.52%
◆ PROPOSAL BENCHMARK	4.47%	1.87%
3 90-DAY TREASURY BILLS	0.50%	0.43%
4 LB AGG BOND INDEX	6.53%	3.34%
5 Pacific Income ST Bond Fd	1.85%	1.06%
6 PIMCO Short Term Bond Fd	2.73%	2.43%
7 Blackrock Core Bond	6.45%	3.24%
8 PIMCO Total Return Fd	8.81%	4.41%
9 Western Core Plus Bond Fd	8.04%	7.56%
10 BlackRock Low Duration Fd	3.38%	4.69%
11 Eaton Vance Inc of Boston Fd	7.75%	17.85%
12 Wells Fargo High Income Fd	7.48%	10.52%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

IV. PERFORMANCE REVIEW*

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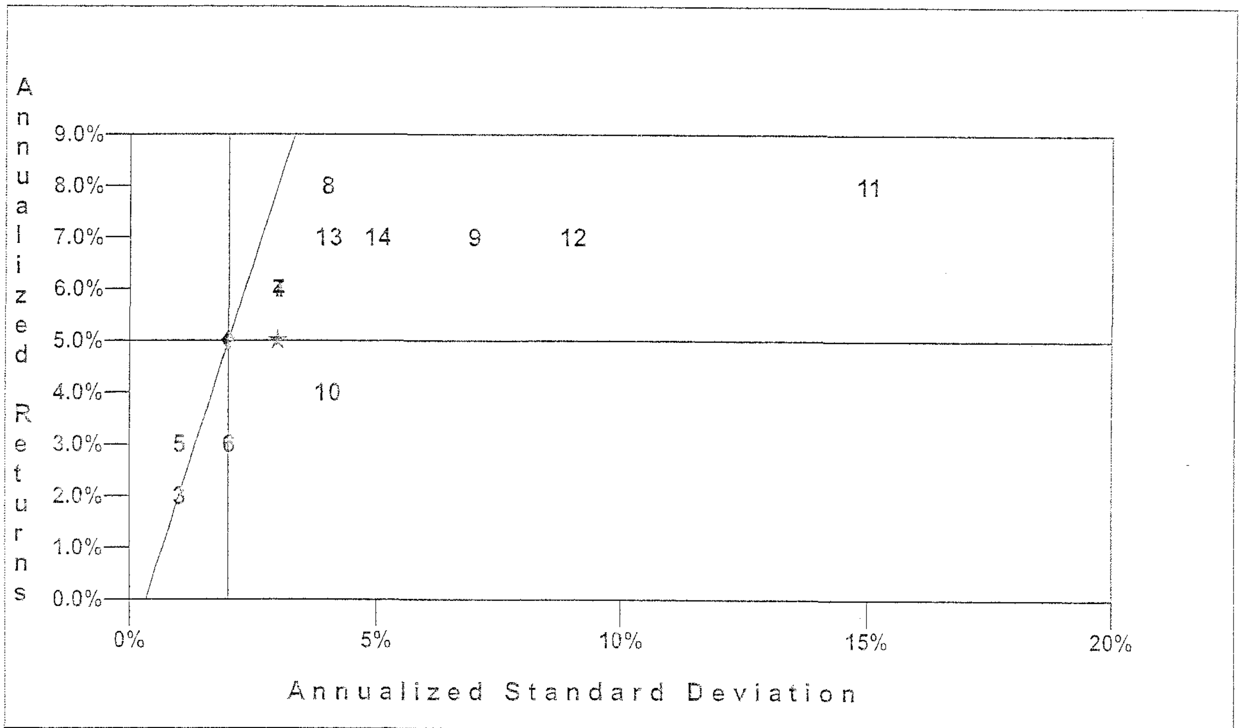
AS OF 10/30/12	RATE OF RETURN	STANDARD DEVIATION
13 Dreyfus Standish Intl Bd Fd	7.64%	4.48%
14 PIMCO Frgn Bd US$ Hedged Fd	8.51%	5.66%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

7-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
☆ PROPOSAL	5.44%	3.17%
◆ PROPOSAL BENCHMARK	4.51%	1.88%
3 90-DAY TREASURY BILLS	1.69%	1.03%
4 LB AGG BOND INDEX	5.92%	3.27%
5 Pacific Income ST Bond Fd	2.61%	1.12%
6 PIMCO Short Term Bond Fd	3.16%	2.09%
7 Blackrock Core Bond	5.88%	3.13%
8 PIMCO Total Return Fd	7.60%	4.38%
9 Western Core Plus Bond Fd	6.92%	6.67%
10 BlackRock Low Duration Fd	3.71%	4.00%
11 Eaton Vance Inc of Boston Fd	7.77%	15.05%
12 Wells Fargo High Income Fd	7.41%	8.93%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
13 Dreyfus Standish Intl Bd Fd	6.50%	4.25%
14 PIMCO Frgn Bd US$ Hedged Fd	6.79%	5.15%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

STEP 4: Ongoing Review Process

After your investment products have been selected, your Financial Advisor will periodically monitor your account's performance. Consulting Group believes that an investment management program does not end with the initial selection of a strategy. Periodic evaluation and monitoring of your account and your long-term investment objectives help you to make periodic adjustments.

Morgan Stanley will provide you with periodic reports showing your account performance. Many Financial Advisors invite clients to review these reports with them either in one-on-one meetings or over the telephone.

Should your financial objectives change, please notify your Financial Advisor so they can reassess your overall investment strategy and suggest appropriate adjustments.

The following services will be provided to you as part of the Select UMA program fee.

Consulting Services

- Define investment objectives and risk tolerance levels
- Develop customized asset allocation strategies
- Recommend appropriate investment products
- Review performance against investment objectives
- Rebalance portfolios periodically (optional)
- Provide manager research reports and periodic economic commentary

Account Services

- Trade executions
- Custody services and safekeeping of securities
- Automatic investment of cash balances

Communications (as required by client)

- Comprehensive periodic reports summarizing performance and portfolio activity
- Monthly account statements
- Trade confirmation of every transaction (unless you request otherwise)
- Periodic review of investment objectives

VI. GLOSSARY OF TERMS

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90-day Treasury Bill Index: An unweighted average of weekly auction offering rates of 90-day Treasury bills. Treasury bills are backed by the full faith and credit of the U.S. government.

Barclays Capital Aggregate Index: The U.S. Aggregate Index covers the dollar-denominated investment-grade fixed-rate taxable bond market, including Treasuries, government-related and corporate securities, MBS pass-through securities, asset-backed securities, and commercial mortgage-based securities. These major sectors are subdivided into more specific subindices that are calculated and published on an ongoing basis. Total return comprises price appreciation/depreciation and income as a percentage of the original investment. This index is rebalanced monthly by market capitalization.

Custom Allocation: Indicates that you have selected the "custom" version of the asset allocation model and have created a customized asset allocation instead of utilizing a model pre-defined by us.

Down1: A portfolio's performance during the most recent "down" cycle in a market. The most recent "down" cycle consists of the most recent quarter in which market performance (as measured by the benchmark) was less than zero. However, if the most recent such quarter was the last in a series of successive quarters in which market performance was less than zero, the most recent "down" cycle consists of that series of successive quarters. (For example, if the last "down" quarter was the fifth successive "down" quarter, then the most recent "down" cycle is the period consisting of those five successive quarters.) The length of the Down1 period may be different from that of the Up1, Up2 and Down2 periods.

Down2: A portfolio's performance during the second most recent "down" cycle in a market. See the definition of "Down1" for how we determine "down" cycles.

FA Discretionary Program: The client has elected to give discretion of the Select UMA account to the Financial Advisor. The FA has ability to select the investment products within the account without the consent of the client. Clients receive a playback of any changes to their account.

Firm Discretionary Program: The client has elected to give discretion of the Select UMA account to Consulting Group. Consulting Group will make the asset allocation and investment product decisions on behalf of the client.

MSCI EAFE Index(Net): The MSCI EAFE Index (Europe, Australasia, Far East) (net) is a free float-adjusted market capitalization index that is designed to measure equity performance of developed markets, excluding the U.S. & Canada. The MSCI EAFE Index consists of the following 22 developed market country indices: Australia, Austria, Belgium, Denmark, Finland, France, Germany, Greece, Hong Kong, Ireland, Israel, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Singapore, Spain, Sweden, Switzerland and the United Kingdom (as of May 2011). Net total return indices reinvest dividends after the deduction of withholding taxes, using(for international indices) a tax rate applicable to non-resident institutional investors who do not benefit from double taxation treaties.

Non-Discretionary Program: The client requires the FA to consult with them before implementing any changes to their account.

Proposal Benchmark: This is a blend of the individual investment products' benchmarks in an allocation equal to the proposal. For example, if the proposal has a 50% US Large Cap Core Equity and a 50% US Core Fixed Income allocation, the Proposal Benchmark would be 50% S&P 500 Index + 50% BC Aggregate Bond Index. The calculation of this blend assumes monthly rebalancing of the weighting of individual product benchmarks back to the target allocation and is likely to differ from actual practice in client accounts. For additional information regarding your Proposal Benchmark, please contact your Morgan Stanley Financial Advisor.

Risk-Return Analysis: On the risk-return graphs, also known as scattergrams or scatterplots, each point on the analysis represents both the return and risk of the proposal and benchmarks. Risk, defined as standard deviation, is measured along the x-axis, while return is measured along the y-axis. The vertical and horizontal lines drawn through the proposal or benchmark divide the graph into four quadrants. The northwest quadrant is sometimes regarded as the most desirable quadrant since any point falling there has both return exceeding the benchmark and less risk than the benchmark. In general, anything plotted to the northwest of another point on the graph is considered to have outperformed the other on a risk-adjusted basis. Historical risk-adjusted performance is not a predictor of future risk-adjusted performance.

S&P 500 Index: Widely regarded as the best single gauge of the U.S. equities market, this world-renowned index includes a representative sample of 500 leading companies in leading industries of the U.S. economy. Although the S&P 500 focuses on the large-cap segment of the market, with over 80% coverage of U.S. equities, it is also an ideal proxy for the total market.

Standard Deviation: The statistical measure of the degree to which an individual value in a probability distribution tends to vary from the mean of the distribution. The standard deviation of performance can be calculated for each security and for the portfolio as a whole. The greater the degree of dispersion, the greater the risk.

Strategic Asset Allocation: A blend of asset classes that we recommend in the Select UMA program to seek to maximize returns in the long run for a given risk tolerance level.

Tactical Asset Allocation: A blend of asset classes that we recommend in the Select UMA program to seek to maximize returns over a shorter period (generally 12 months or so) for a given risk tolerance.

Up1: A portfolio's performance during the most recent "up" cycle in a market. The most recent "up" cycle consists of the most recent quarter in which market performance (as measured by the benchmark) was greater than zero. However, if the most recent such quarter was the last in a series of successive quarters in which market performance was greater than zero, the most recent "up" cycle consists of that series of successive quarters. (For example, if the last "up" quarter was the fifth successive "up" quarter, then the most recent "up" cycle is the period consisting of those five successive quarters.) The length of the Up1 period may be different from that of the Up 2, Down1 and Down2 periods.

Up2: A portfolio's performance during the second most recent "up" cycle in a market. See the definition of "Up1" for how we determine "up" cycles.

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IMPORTANT DISCLOSURES

Although the statements of fact and data in this proposal have been obtained from, and are based upon, sources that we believe to be reliable, we do not guarantee their accuracy, and any such information may be incomplete or condensed. All opinions included in this material constitute our judgment as of the date of this material and are subject to change without notice. This material is provided for informational purposes only and is not intended as an offer or solicitation with respect to the purchase or sale of any security. The information shown is provided by the Consulting Group and Sub-Managers and, where provided by Sub-Managers, is not independently verified by us.

Performance. For those Select UMA Sub-Managers that participate in the Morgan Stanley Fiduciary Services program, and beginning with the first full quarter after the acceptance by the Sub-Manager of the first Fiduciary Services client in this style, the composite performance figures represent the Sub-Manager's actual Morgan Stanley Fiduciary Services performance in this style (for all fee paying accounts with no investment restrictions), and are calculated by Morgan Stanley. Performance figures for Sub-Managers that do not participate in the Fiduciary Services program (and for Sub-Managers that do participate in the Fiduciary Services program, performance figures for periods prior to the Sub-Managers participation) are for a composite compiled by the Sub-Manager, and are calculated by the Sub-Manager. Please note that some of the performance information for the Sub-Manager depicts the performance of accounts employing similar, but not the actual, investment strategies that will be used for Select UMA clients. Because the accounts contained in the Sub-Manager's composite were not managed contemporaneously with the Select UMA accounts, may be different in size than a typical Select UMA account or may have been managed with a view toward different client needs and considerations, the specific securities held and rates of return achieved for Select UMA accounts may differ from those of the Sub-Manager's composite. Also, the Sub-Manager's composite may have included IPO investments, while Select UMA accounts do not invest in IPOs. Actual results may vary.

Since Sub-Managers may use different methods of selecting accounts to be included in their performance composites and for calculating performance, returns of different Sub-Managers may not be comparable.

Each Sub-Manager, as investment adviser to the client, will exercise discretion to select securities for the client's account by (i) delivering a model portfolio to the Overlay Manager(which is part of Morgan Stanley), which the Overlay Manager will implement (subject to any client instructions accepted by the Overlay Manager); or (ii) (in the case of an executing Sub-Manager) implementing its investment decisions directly.

The investment results depicted herein represent historical gross performance with no deduction for investment management fees or any applicable insurance or annuity charges. Actual returns will be reduced by expenses, including management fees. Please see the Select UMA ADV brochure for a full disclosure of the fee schedule. Because the fees are deducted quarterly, the fees will have a compounding effect on performance and can be material. For example, on an account with an initial value of $100,000 and a 2% annual fee, if the gross performance is 10% per year over a three-year period, the compounding effect of the fees will result in a net compound rate of return of approximately 7.81% per year over a three-year period, and the total value of the client's portfolio at the end of the three-year period would be approximately $133,100 without the fee and $125,307 with the fee.

Performance results include all cash and cash equivalents, are time weighted, annualized for time periods greater than one year and include realized and unrealized capital gains and losses and reinvestment of dividends, interest and income.

As a result of recent market activity, current performance may vary from the figures shown. Please contact your Financial Advisor for up-to-date performance information. Past performance is not a guarantee of future results. Diversification does not ensure a profit or protect against loss.

General Information. **All Funds are sold by prospectus, which contains more complete information about the fund. Please contact your Financial Advisor for copies. Please read the prospectus and consider the fund's objectives, risks, charges and expenses carefully before investing. The prospectus contains this and other information about the fund.**

Return and principal value of investments will fluctuate and, when redeemed, may be worth more or less than their original cost. Investments are not FDIC insured or bank guaranteed, and investors may lose money. There is no guarantee that past performance or information relating to return, volatility, style reliability and other attributes will be predictive of future results. The value of an investor's shares of any fund will fluctuate and, when redeemed, may be worth more or less than the investor's cost.

If the client selects a "custom" version of the model for the client's unified managed account, unless the client has elected Financial Advisor Discretion, the client (not Morgan Stanley) will determine the initial asset allocation for the model and will be responsible thereafter for any adjustments to the asset allocation of the model. The client's Financial Advisor may utilize recommendations of the our Global Investment Committee ("GIC") as a resource in assisting the client in defining a custom model. If the Financial Advisor does utilize GIC recommendations in connection with defining a custom model, there is no guarantee that any model defined will in fact mirror or track GIC recommendations.

Individual retirement accounts and other retirement plan clients that participate in Morgan Stanley advisory programs may be prohibited from purchasing investment products managed by affiliates of Morgan Stanley.

Morgan Stanley Smith Barney LLC, its affiliates, and its employees are not in the business of providing tax or legal advice. These materials and any tax-related statements are not intended or written to be used, and cannot be used or relied upon, by any taxpayer for the purpose of avoiding tax penalties. Tax-related statements, if any, may have been written in connection with the "promotion or marketing" of the transaction(s) or matters(s) addressed by these materials, to the extent allowed by applicable law. Any taxpayer should seek advice based on the taxpayer's particular circumstances from an independent tax advisor. The performance of tax-managed accounts is likely to vary from that of non-tax managed accounts.

To obtain Tax Management Services, a client must complete the Tax Management Form, and deliver the signed form to us. For more information on Tax Management Services, including its features and limitations, please ask your Financial Advisor for the Tax Management Form. Review the form carefully with your tax advisor. Tax Management Services (a) apply only to equity investments in separate account sleeves of client accounts; (b) are not available for all accounts or clients; and (c) may adversely impact account performance. Tax Management Services do not constitute tax advice or a complete tax-sensitive investment management program. There is no guarantee that Tax Management Services will produce the desired tax results.

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Investing in the market entails the risk of market volatility. The value of all types of securities, including Funds, may increase or decrease over varying time periods.

To the extent the investments depicted herein represent international securities, you should be aware that there may be additional risks associated with international investing, including foreign economic, political, monetary and/or legal factors, changing currency exchange rates, foreign taxes, and differences in financial and accounting standards. These risks may be magnified in emerging markets. International investing may not be for everyone. Small and mid-capitalization companies may lack the financial resources, product diversification and competitive strengths of larger companies. In addition, the securities of small capitalization companies may not trade as readily as, and be subject to higher volatility than, those of larger, more established companies.

Ultra-short bond funds are Funds that generally invest in fixed income securities with very short maturities, typically less than one year. They are not money market funds. While money market funds attempt to maintain a stable net asset value, an ultra-short bond fund's net asset value will fluctuate, which may result in the loss of the principal amount invested. They are therefore subject to the risk associated with debt securities such as credit and interest rate risk.

Bonds are subject to interest rate risk. When interest rates rise, bond prices fall; generally, the longer a bond's maturity, the more sensitive it is to this risk. Bonds may also be subject to call risk, which allows the issuer to retain the right to redeem the debt, fully or partially, before the scheduled maturity date. Proceeds from sales prior to maturity may be more or less than originally invested due to changes in market conditions or changes in the credit quality of the issuer. High-yield bonds are subject to additional risks such as increased risk of default and greater volatility because of the lower credit quality of the issues.

In unified managed account programs at Morgan Stanley, alternative investments are limited to primarily U.S.-registered open-end mutual funds and exchange-traded funds (ETFs) that seek to pursue alternative investment strategies or returns. Mutual funds in this category may employ various investment strategies and techniques for both hedging and more speculative purposes, such as short selling, leverage, derivatives and options, which can increase volatility and the risk of investment loss. Alternative investments are not suitable for all investors.

Investing in commodities entails significant risks. Commodity prices may be affected by a variety of factors at any time, including, but not limited to, (i) changes in supply and demand relationships, (ii) governmental programs and policies, (iii) national and international political and economic events, war and terrorist events, (iv) changes in interest and exchange rates, (v) trading activities in commodities and related contracts, (vi) pestilence, technological change and weather, and (vii) the price volatility of a commodity. In addition, the commodities markets are subject to temporary distortions or other disruptions due to various factors, including lack of liquidity, participation of speculators and government intervention.

The risks of investing in REITs are similar to those associated with direct investments in real estate: lack of liquidity, limited diversification, and sensitivity to economic factors such as interest rate changes and market recessions.

Derivatives, in general, involve special risks and costs that may result in losses. The successful use of derivatives requires sophisticated management in order to manage and analyze derivatives transactions. The prices of derivatives may move in unexpected ways, especially under abnormal market conditions. In addition, correlation between the particular derivative and an asset or liability of the investment portfolio may not be what the investment manager expected. Some derivatives are "leveraged" and therefore may magnify or otherwise increase investment losses. Other risks include the potential inability to terminate or sell derivative positions, as a result of counterparty failure to settle or other reasons.

In this proposal, "Morgan Stanley," "we," "us," or "our" apply to Morgan Stanley Smith Barney LLC.

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Select UMA®

A personalized investment plan for

ACAA

Prepared by:

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Morgan Stanley

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YOUR INVESTMENT PROFILE

One of the advantages of a consulting relationship is that it provides an objective framework for making investment decisions. This process often includes the development of a personalized, long-term investment strategy.

Consulting Group's four-step investment process is designed to help investors seek to achieve their investment objectives, attain portfolio diversification and reduce risks over time.

- STEP ONE: Set Investment Objectives

  Financial Advisors help you to define your investment objectives based on three critical factors: your goals, time horizon and risk tolerance.

- STEP TWO: Define Investment Strategy

  Based on your investment objectives, your Financial Advisor recommends an asset allocation strategy designed to provide proper diversification.

- STEP THREE: Evaluate and Select Investment Products

  Financial Advisors help you to identify investment products that may be most appropriate given your asset allocation strategy. The investment products may or may not be affiliated with us.

- STEP FOUR: Ongoing Review Process

  Financial Advisors consult with you periodically to determine whether short-term or long-term changes are needed in the asset allocation strategy or investment products in your portfolio.

For more information on Consulting Group's Four-Step Process, please speak to your Financial Advisor.

Step 1: Set Investment Objectives

Our discussion of your financial needs and goals was the start of the process that enabled us to learn about you as an investor. Let's review what you told us:

- You will be investing $4,500,000.
- You have selected the Firm Discretionary Program.
- You have selected the "tactical" version of the asset allocation model.

The following information depicts our understanding of your investment objectives and risk tolerance for your proposed Morgan Stanley Consulting Group Select UMA account.

Please review this information carefully. If you do not agree with this or any other information included in this proposal, please notify your Financial Advisor immediately. Also, please notify your Financial Advisor immediately of any change in the information in this proposal (including any change in your investment objectives or risk tolerance). To the extent that the investment suitability and objectives information noted below conflicts with any other information you communicate to us (e.g., via telephone, e-mail, or Investment Policy Statement), the information contained in this proposal shall control with respect to the management of this account.

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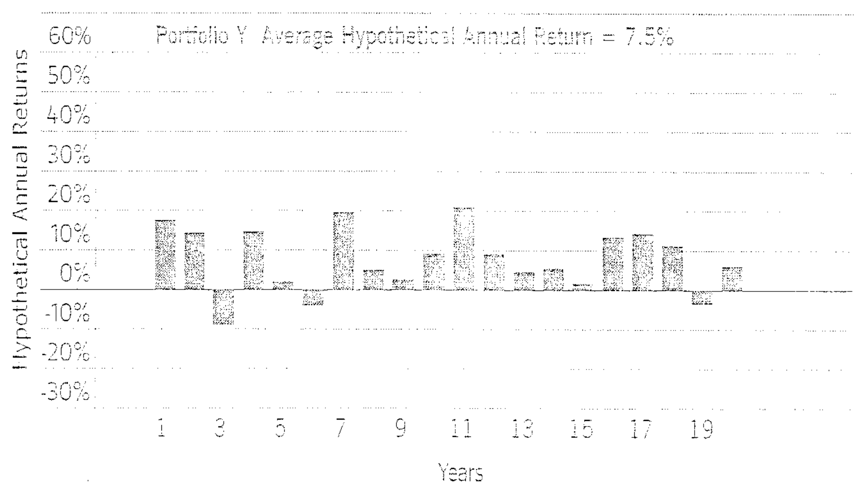
- Your primary purpose for opening this account is wealth accumulation.
- We understand you need to take regular withdrawals from this account. You will need between 2% and 4% of this account's current value annually.
- You expect to begin withdrawing funds from this account immediately, for your primary investment objective.
- Once you begin to withdraw funds from this account for your primary investment objective, you anticipate that you will withdraw all funds within 6 to 10 years.
- For this account, limiting risk and maximizing returns are of equal importance to you. You are willing to accept moderate risk and a moderate chance of loss to seek moderate returns.
- Given your investment goals for this account, you would choose a hypothetical portfolio over a 20-year period similar to the following:



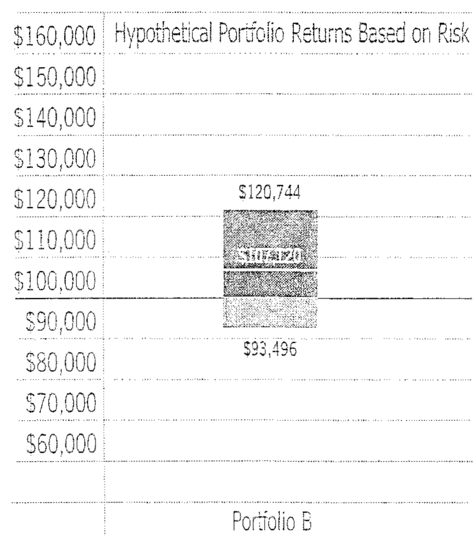
This portfolio is constructed to seek moderate annual returns, risk and volatility. Please note that this is a hypothetical example only, for the purpose of gauging your tolerance for risk. This does not represent any actual historical results and does not include fees or charges that would lower your return. Actual results of any particular account may be less than the "Hypothetical Annual Returns" and "Average Hypothetical Annual Return" shown above, and may be negative.

- The risk of a portfolio suffering a decrease in value (having a negative return) is often a primary concern for investors. In seeking to achieve potentially higher returns, however, an investor must be willing to accept greater risk. Given your investment objective for this account, you would be most comfortable investing this account in a hypothetical portfolio similar to the following:

Portfolio	Hypothetical Value of $100,000 After 1 Year	Hypothetical Chance of Losing Money After 1 Year
Portfolio B	$107,120	14.8%

This portfolio is constructed to accept a somewhat lower hypothetical value, but also to seek a somewhat lower chance of losing money, after one year. Please note that this is a hypothetical example only, for the purpose of gauging your tolerance for risk. This does not represent any actual historical results and does not include fees or charges that would lower your return. Actual results of any particular account may be less than the "Hypothetical Value" shown above, and may be negative.

- The bar chart below shows a range of hypothetical one-year ending values for a $100,000 initial investment in a portfolio. The hypothetical value of the average return for that portfolio is shown in the center of the bar. Given possible outcomes for various portfolios, you would consider the following hypothetical portfolio to be suitable for you in light of your investment objective for this account:



At the end of a given year, this portfolio has hypothetical ending values between $120,744 (21% return) and $93,496 (negative 7% return). The hypothetical average ending value of this portfolio after one year is approximately $107,120 (7% return). This portfolio is constructed to accept a somewhat lower hypothetical average ending value, but also to seek a somewhat narrower range of one-year ending values.

It is important to remember that a hypothetical portfolio such as that shown above is more likely to achieve the average return over long-term holding periods. Please note that this is only a hypothetical example, for the purpose of measuring your tolerance for risk. Actual results will vary, and may be worse than the lowest outcome shown on the bar chart above. This bar chart does not represent any actual historical results and does not include fees or charges that would lower your return.

- Inflation can greatly erode the return on your investments, especially over time. For this account, you prefer a portfolio that has the potential to exceed inflation moderately over the long run and are willing to accept moderate short-term fluctuations in value (and a moderate potential for loss) to achieve this goal.

- Sometimes investment losses are permanent, sometimes they are prolonged and sometimes they are short-lived. We understand that if you experienced substantial investment losses in this account, you would sell your investments immediately.

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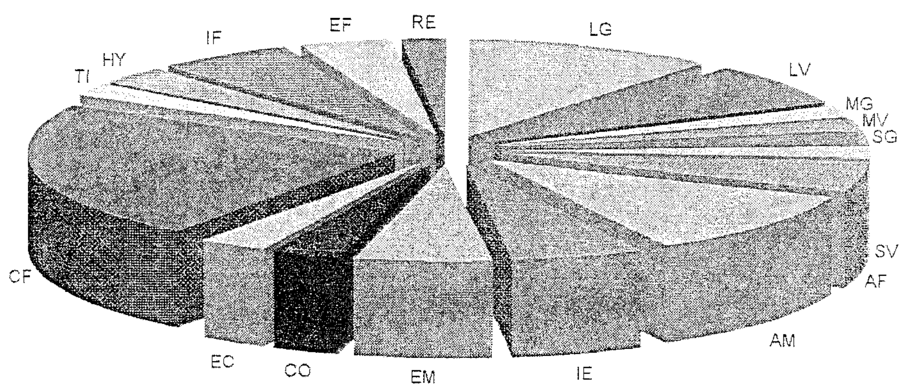
ASSET ALLOCATION

Step 2: Define Investment Strategy

Asset allocation can be one of the most effective investment techniques investors can employ. The appropriate asset allocation policy can provide diversification of your portfolio, lower overall portfolio fluctuation and position your portfolio to take advantage of developing investment opportunities. This is conducted by apportioning your portfolio among different types of investments that may include stocks, bonds, money market instruments and other asset categories. While it is a widely held opinion that diversification is a prudent investment technique, diversification does not ensure against loss.

The following asset allocation is either the asset allocation that we recommend for you based on your investment objectives or a custom allocation that you have selected based on your preferences.



Asset Class	Target
US Large Growth Equity (LG)	11.00%
US Large Value Equity (LV)	7.00%
US Mid Cap Growth Equity (MG)	2.00%
US Mid Cap Value Equity (MV)	2.00%
US Small Growth Equity (SG)	2.00%
US Small Value Equity (SV)	2.00%
Managed Futures (AF)	5.00%
Hedged Multi-Strategy (AM)	11.00%
International Equity (IE)	6.00%
Emerging Markets Equity (EM)	6.00%
Commodities - Diversified (CO)	3.00%
Ultra Short Duration Fixed Inc (EC)	3.00%
US Core Fixed Inc (CF)	23.00%
Inflation Linked Securities (TI)	2.00%
High Yield Fixed Income (HY)	3.00%
International Bonds (IF)	6.00%

*Due to rounding, total may not add to 100.00%.

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Asset Class	Target
Emerging Markets Fixed Income (EF)	4.00%
REITs (RE)	2.00%
Total*	100.00%

*Due to rounding, total may not add to 100.00%.

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YOUR PORTFOLIO

Step 3: Evaluate and Select Investment Products

Our Consulting Group Investment Advisor Research department("CG IAR") evaluates most investment products offered in the Select UMA program. CG IAR then reviews these investment products periodically to ensure that they continue to meet Consulting Group's standards. CG IAR does not evaluate investment products affiliated with us (including investment products with "Morgan Stanley," "CGCM," or "GIS" in their names).

In addition, we will monitor the investment products you ultimately select for your portfolio. The purpose of this process is to evaluate whether the investment products selected continue to be compatible with your stated investment objectives and tolerance for risk.

The table below illustrates the percentage of your assets that would be invested in the investment products listed if this proposal is accepted.

Select UMA Model 4

Asset Class	Investment Product	Investment Type*	% of Portfolio	Investment Product Benchmark
US Large Growth Equity	Winslow Large Cap Growth	SMA	11.00%	Russell 1000 Gr
US Large Value Equity	NWQ Large Value	SMA	7.00%	Russell 1000 Vl
US Mid Cap Growth Equity	Ivy Mid Growth Fd	MF	2.00%	Russell Mid Cap Gr
US Mid Cap Value Equity	Mgrs AMG Systematic M V Fd	MF	2.00%	Russell Mid Cap Vl
US Small Growth Equity	JP Morgan Dynamic Sm Growth Fd	MF	2.00%	Russell 2000 Gr
US Small Value Equity	Cambiar Small Value Fd	MF	2.00%	Russell 2000 Vl
Managed Futures	AQR Managed Futures Strat Fd	MF	5.00%	ML 3 mth TBill - G0O1
Hedged Multi-Strategy	Goldman Sachs Abs Return Tr Fd	MF	11.00%	HFRI Fund Weighted Comp
International Equity	Thornburg International Val Fd	MF	6.00%	MSCI AC World ex US NET
Emerging Markets Equity	Virtus Emerging Mkts Opps Fd	MF	6.00%	MSCI EM net
Commodities - Diversified	Eaton Vance Commodity Strat Fd	MF	3.00%	DJ UBS Commodity
Ultra Short Duration Fixed	PIMCO Short Term Bond Fd	MF	3.00%	90-Day T-Bills
US Core Fixed Inc	MetWest Total Rtn Bd Fd	MF	23.00%	BC Aggregate
Inflation Linked Securities	BlackRock Infl Protected Bd Fd	MF	2.00%	BC Gbl Inf Linked US TIPS
High Yield Fixed Income	Eaton Vance Inc of Boston Fd	MF	3.00%	BC HY
International Bonds	PIMCO Frgn Bd US$ Hedged Fd	MF	6.00%	Citi Non-US WGBI Hed
Emerging Markets Fixed	Western Em Debt Port Fd	MF	4.00%	JPM EMBI Gbl
REITs	ING Global Real Estate Fd	MF	2.00%	S&P BMI Property Develope

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represents a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

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Asset Class	Investment Product	Investment Type*	% of Portfolio	Investment Product Benchmark
Total			100.00%	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represents a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

EVALUATION OF INVESTMENT PRODUCTS

In the Select UMA program, we offer a wide range of Investment Products (including Sub-Managers, mutual funds and ETFs) that we have selected and approved. We also offer affiliated investment products, which CG IAR does not evaluate or approve. The remainder of this section ("EVALUATION OF INVESTMENT PRODUCTS"), as well as any references in this proposal to Investment Products being evaluated or approved (or on the "Focus List" or "Approved List") does not apply to affiliated investment products.

Morgan Stanley CG IAR evaluates Investment Products. CG IAR may delegate some or all of its functions to an affiliate or third party. Investment Products may only participate in the Select UMA program if they are on CG IAR's Focus List or Approved List discussed below. The Focus List and Approved List are available at www.morganstanleyindividual.com/accountoptions/managedmoney/manager/default.asp (or you can ask your Financial Advisor for these lists). Only some of the Investment Products may be available in the Select UMA program.

In addition to requiring that Investment Products be on the Focus List or Approved List, we look at other factors in determining which Investment Products we offer in the Select UMA program, including:

- program needs (such as whether we have a sufficient number of Investment Products available in an asset class),
- client demand and
- the Sub-Manager's or Fund's minimum account size.

We automatically terminate Investment Products in the Select UMA program if CG IAR downgrades them to "Not Approved." We may terminate Investment Products from the program for other reasons (e.g., the Investment Product has a low level of assets under management in the program, the Investment Product has limited capacity for further investment, or the Investment Product is not complying with our policies and procedures).

Focus List. To be considered for the Focus List, Investment Products provide CG IAR with relevant documentation on the strategy being evaluated, which may include sample portfolios, asset allocation histories, its Form ADV (the form that investment managers use to register with the SEC), past performance information and marketing literature. For verification purposes, as part of the review process, CG IAR may compare the Sub-Manager's/Fund's reported performance with the performance of a cross-section of actual accounts calculated by CG IAR. CG IAR personnel may also interview the Sub-Manager or Fund and its key personnel, and examine its operations. Following this review process, Investment Products are placed on the Focus List if they meet the required standards for Focus List status.

CG IAR periodically reviews Investment Products on the Focus List. CG IAR considers a broad range of factors (which may include investment performance, staffing, operational issues and financial condition). Among other things, CG IAR personnel interview each Sub-Manager or Fund periodically to discuss these matters. If CG IAR is familiar with a Sub-Manager or Fund following repeated reviews, CG IAR is likely to focus on quantitative analysis and interviews and not require in-person meetings. CG IAR may also review the collective performance of a composite of the Morgan Stanley accounts managed by a Sub-Manager/Fund and compare this performance to overall performance data provided by the Sub-Manager/Fund, and then investigate any material deviations.

Approved List. The process for considering Investment Products for the Approved List is less comprehensive than for the Focus List, and evaluates various qualitative and quantitative factors. These may include personnel depth, turnover and experience; investment process; business and organization characteristics; and investment performance. CG IAR may use an algorithm – a rules-based scoring mechanism – that reviews various qualitative and quantitative factors and ranks each Investment Product in a third party database. (Not all Investment Products reviewed for the Approved List are subject to this algorithm.) CG IAR analysts analyze the information contained in the algorithm to gauge the completeness and consistency of the data which drive the rankings, and then send the Sub-Manager or Fund additional information requests. CG IAR then determines whether the Investment Product meets the standards for Approved List status. Furthermore, CG IAR may evaluate an Investment Product under the evaluation process for the Focus List but then decide to instead put it on the Approved List.

CG IAR periodically evaluates Investment Products on the Approved List to determine whether they continue to meet the Approved List standards.

Changes in Status from Focus List to Approved List. In light of the differing evaluation methodology and standards for the Focus List and Approved List, CG IAR may determine that an Investment Product no longer meets the criteria for the Focus List or will no longer be reviewed under the Focus List review process, but meets the criteria for the Approved List. If so, we generally notify program clients regarding such status changes on a quarterly basis.

Changes in Status to Not Approved. CG IAR may determine that an Investment Product no longer meets the criteria under either evaluation process and, therefore, the Investment Product will no longer be recommended in our investment advisory programs. We notify affected clients of these downgrades. You cannot retain a downgraded Sub-Manager or Fund in your Select UMA account and must select a replacement from the Approved List or Focus List, that is available in the program, if you wish to retain the program's benefits in respect of the affected assets.

In some circumstances, you may be able to retain terminated Investment Products in another advisory program or in a brokerage account, subject to the regular terms and conditions applying to that program or account. Ask your Financial Advisor about these options.

In the Select UMA program, we generally specify a replacement Investment Product for a terminated Investment Product. In selecting the replacement Investment Product, CG IAR generally looks for an Investment Product in the same asset class, and with similar attributes and holdings to the terminated Investment Product. The replacement Investment Product will typically be on the Focus List.

Watch Policy. CG IAR has a "Watch" policy for Investment Products on the Focus List and Approved List. Watch status indicates that, in reviewing an Investment Product, CG IAR has identified specific areas of the Sub-Manager's or Fund's business that (a) merit further evaluation by CG IAR and (b) may, but are not certain to, result in the Investment Product becoming "Not Approved." Putting an Investment Product on Watch does not signify an actual change in CG IAR opinion nor is it a guarantee that CG IAR will downgrade the Investment Product. The duration of a Watch status depends on how long CG IAR needs to evaluate the Investment Product and for the Investment Product to address any areas of concern. For additional information, ask your Financial Advisor for a copy of CG IAR's Watch Policy.

Tactical Opportunities List. CG IAR also has a Tactical Opportunities List. This consists of certain Investment Products on the Focus List or Approved List recommended for investment at a given time based in part on then-existing tactical opportunities in the market.

III. FEE SCHEDULE

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Morgan Stanley Fee[1]	
$0 - $249,999	1.00000%
$250,000 - $499,999	1.00000%
$500,000 - $999,999	0.90000%
$1,000,000 - $1,999,999	0.90000%
$2,000,000 - $4,999,999	0.80000%
Amount Over $5,000,000	0.60000%

Estimated Total Client Fee Rate[2]	
Morgan Stanley Fee	[1] 0.8560%
Sub-Manager Fee	0.0539%
Overlay Manager Fee[3]	0.1200%
Total Effective Rate (%)	[illegible]

[1] If the Financial Advisor Discretion option is chosen, the Morgan Stanley Fee includes an additional charge for FA discretionary services of 25% of Morgan Stanley's basic advisory Fee.

[2] The Estimated Total Client Fee Rate is based on the account asset value shown in the Investment Profile section above, and includes Morgan Stanley, Sub-Manager and Overlay Manager fees, and the asset allocation percentages shown in the Portfolio Strategy Recommendations section above. The actual Total Client Fee Rate may vary, depending on the account asset value and asset allocation percentages. From time to time, certain additional fees and charges may apply. For more details, see the Select UMA ADV brochure, available from your Financial Advisor or at www.morganstanley.com/ADV.

[3] Fee compensates the Overlay Manager (which is part of Morgan Stanley) for portfolio rebalancing and other administrative functions.

Please note that performance illustrations used in this proposal do not include the impact of the fees set forth above or any applicable insurance or annuity charges. These expenses will reduce the actual performance of your account. Because the fees are deducted quarterly, the fees will have a compounding effect on performance and can be material. For example, for an account with an advisory fee of 2%, if the gross performance is 10%, the compounding effect of the fees will result in a new annual compound rate of return of approximately 7.81%. After a three-year period with an initial investment of $100,000, the total value of the client's portfolio would be approximately $133,100 without the fee and $125,307 with the fee.

Financial Advisors receive as compensation a percentage of the total Morgan Stanley fee you pay. This percentage is the same whether you choose to invest based on one proposal, a blend of several, or your own independent allocation approach, but obviously the dollar amount received will vary based on the effective rate and the amount you choose to allocate to a particular Investment Product. For more details, please refer to the discussion of fees in the Select UMA ADV brochure and your Select UMA Agreement.

Asset Class	Investment Product	Investment Product Type*	Model Asset Allocation %	Sub-Manager Fee % (SMA Only)
Managed Futures	AQR Managed Futures Strat Fd	MF	5.00%	
Hedged Multi-Strategy	Goldman Sachs Abs Return Tr Fd	MF	11.00%	
US Core Fixed Inc	MetWest Total Rtn Bd Fd	MF	23.00%	
Commodities - Diversified	Eaton Vance Commodity Strat Fd	MF	3.00%	
Ultra Short Duration Fixed Inc	PIMCO Short Term Bond Fd	MF	3.00%	
Emerging Markets Fixed Income	Western Em Debt Port Fd	MF	4.00%	
Emerging Markets Equity	Virtus Emerging Mkts Opps Fd	MF	6.00%	
High Yield Fixed Income	Eaton Vance Inc of Boston Fd	MF	3.00%	
International Equity	Thornburg International Val Fd	MF	6.00%	
International Fixed Income	PIMCO Frgn Bd US$ Hedged Fd	MF	6.00%	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represent a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

III. FEE SCHEDULE

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Asset Class	Investment Product	Investment Product Type*	Model Asset Allocation %	Sub-Manager Fee % (SMAOnly)
US Large Growth Equity	Winslow Large Cap Growth	SMA	11.00%	0.28%
US Large Value Equity	NWQ Large Value	SMA	7.00%	0.33%
US Mid Cap Growth Equity	Ivy Mid Growth Fd	MF	2.00%	
US Mid Cap Value Equity	Mgrs AMG Systematic M V Fd	MF	2.00%	
REITs (Real Estate Inv. Trust)	ING Global Real Estate Fd	MF	2.00%	
US Small Growth Equity	JP Morgan Dynamic Sm Growth	MF	2.00%	
US Small Value Equity	Cambiar Small Value Fd	MF	2.00%	
Inflation Linked Securities	BlackRock Infl Protected Bd Fd	MF	2.00%	

* Manager/Fund Names that are followed by an "SMA" or "MF" or "ETF" represent a separately managed account, a mutual fund, and an exchange-traded fund, respectively.

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Mutual Fund & ETF Performance

The performance below shows the average annual total return of each mutual fund/ETF ("Fund") included in the proposal for the periods shown below, as well as since the Fund's inception. To the extent that any of these funds include a sales load, the effect of such a load is reflected in the performance quotations. We are required to illustrate the maximum possible effect of the load by applicable law; however, if you accept this proposal, the funds purchased for you through this program will have such sales loads waived. However, your account will be charged the Select UMA fee, so your returns would differ from – and be lower than – those shown below.

The impact of Select UMA program fees can be material. These program fees are deducted quarterly and have a compounding effect on performance. For example, on an account with a 1% annual fee, if the gross annual performance is 6%, the compounding effect of the fees will result in a net performance of approximately 4.94% after one year, 4.81% after three years and 4.66% after five years. See the Select UMA ADV brochure for an explanation of the fees and charges that would apply if you invest in a Fund through the Select UMA program.

As with any Fund investment, you should consider the investment objectives, risks, charges and expenses of the Funds carefully before investing. Your Financial Advisor is available to discuss these issues in detail with you. Additionally, the prospectus of each Fund contains this information and other information about the Fund. Prospectuses and current performance data are available on our website at www.morganstanley.com or through your Financial Advisor.

The performance data set forth below represents past performance. Past performance does not guarantee future results. Investment returns and principal value of an investment will fluctuate so that an investor's shares may be worth more or less than their original cost upon redemption. Current performance may be lower or higher than the performance data quoted. For Funds with multiple share classes, the data may represent the actual performance of the oldest share class prior to the inception of newer share classes. This data is adjusted to reflect the expenses of the newer share classes.

Performance data as of the most recent month-end may be obtained by contacting your Financial Advisor, calling the fund company at the toll-free number shown in this proposal, or through www.morganstanley.com.

Gross Expense Ratio reflects the annual percentage of a Fund's assets paid out in expenses which include any 12b-1, transfer agent and all other asset-based fees associated with a Fund's daily operations and distribution.

Net Expense Ratio reflects actual expenses paid by a Fund as well as any fee waivers or expense reimbursements, which may be voluntary or mandated by contract for a certain time period. Specific details about expense ratios are outlined in a Fund's prospectus.

* Please see the important performance disclosures located at the end of this Proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

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Average Annual Total Returns as of September 2012

Fund Name	Symbol	Inception Date	1-Year Return	5-Year Return	10-Year Return	Since Inception	Gross Expense Ratio	Net Expense Ratio	Phone Number
AQR Managed Futures Strat Fd	AQMIX	2010/01	-3.29%	NA	NA	0.32%	1.40%	1.35%	866-290-2688
BlackRock Infl Protected Bd Fd	BPRIX	2004/06	8.77%	8.06%	NA	7.00%	0.61%	0.45%	800-441-7762
Cambiar Small Value Fd	CAMSX	2004/08	29.06%	4.78%	NA	9.53%	1.45%	1.32%	866-777-8227
Eaton Vance Inc of Boston Fd	EIBIX	1972/06	16.48%	7.75%	10.13%	9.09%	0.77%	0.77%	800-262-1122
Eaton Vance Commodity Strat Fd	EICSX	2010/04	5.79%	NA	NA	3.73%	1.27%	1.25%	800-262-1122
Goldman Sachs Abs Return Tr Fd	GJRTX	2008/05	4.68%	NA	NA	-1.55%	1.21%	1.18%	800-621-2550
Virtus Emerging Mkts Opps Fd	HIEMX	1997/10	21.78%	3.97%	18.06%	8.65%	1.42%	1.42%	800-243-1574
ING Global Real Estate Fd	IGLIX	2005/06	26.48%	-1.94%	11.62%	11.11%	0.99%	0.99%	800-992-0180
Ivy Mid Growth Fd	IYMIX	2007/04	24.63%	5.79%	11.72%	5.67%	1.05%	1.05%	800-777-6472
JP Morgan Dynamic Sm Growth Fd	JDSCX	1997/05	33.97%	0.75%	8.76%	7.73%	1.22%	1.10%	800-480-4111
MetWest Total Rtn Bd Fd	MWTIX	2000/03	11.01%	8.88%	8.33%	7.72%	0.41%	0.41%	800-241-4671
PIMCO Frgn Bd US$ Hedged Fd	PFBPX	1992/12	11.61%	8.50%	6.51%	7.81%	0.60%	0.60%	888-877-4626
PIMCO Short Term Bond Fd	PTSPX	1987/10	3.21%	2.73%	2.96%	4.79%	0.56%	0.55%	888-877-4626
Western Em Debt Port Fd	SEMDX	1996/10	18.65%	9.70%	13.79%	11.62%	1.00%	0.95%	877-721-1926
Mgrs AMG Systematic M V Fd	SYIMX	2006/12	29.56%	1.63%	NA	4.19%	0.89%	0.88%	800-548-4539
Thornburg International Val Fd	TGVIX	1998/05	14.46%	-3.34%	10.85%	8.31%	0.88%	0.88%	800-847-0200

* Please see the important performance disclosures located at the end of this Proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

IV. PERFORMANCE REVIEW*

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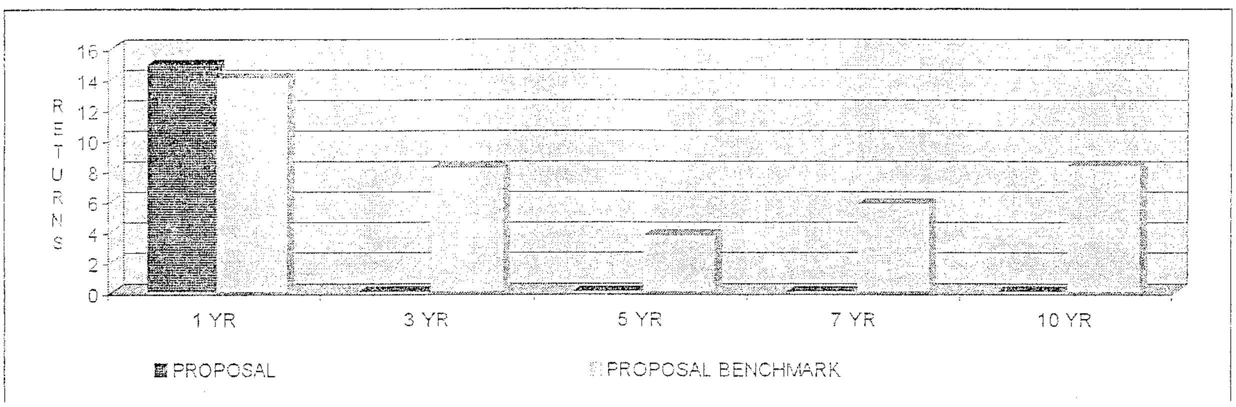
The performance data designated as "Proposal" below on this page and on each of the following pages of this proposal is intended to model what the return of a portfolio would have been had you been invested in the investment products recommended in this proposal, in the percentages recommended, over the time periods shown. These returns are hypothetical returns based on a simulated account (not an actual account). You would not necessarily have obtained these performance results if you had held this portfolio for the periods indicated. Actual performance results of accounts vary due to factors such as timing of contributions and withdrawals, and rebalancing schedules. Also, fees would apply to, and reduce the performance of, investment products included in this hypothetical portfolio. The selection of investment products in this proposal reflects the benefit of hindsight based on historical rates of return. This performance is presented for illustrative purposes only.

With respect to third-party separately managed accounts ("SMAs"), the performance information is based on other accounts of the investment Sub-Manager that operated with substantially similar investment objectives and policies during the time periods indicated. With respect to affiliated investment products, the performance information is that of the affiliated investment product in a Consulting Group investment advisory program other than Select UMA. The data designated as "Proposal Benchmark" is derived from the stated benchmark of each investment product included in the weightings set forth in our recommendation. As noted above, past performance does not guarantee or predict future results.

It is important to note that the performance set forth below does not take into account the fees that would be charged to the account. As illustrated in the Performance Disclosures at the end of this proposal, if an account had been in existence for the time periods shown, its performance would be lower than that shown by an amount that is directly proportionate to the fee charged. Please see the Fee Schedule for an illustration of the impact of fees on account performance.

PERFORMANCE STATISTICS BEFORE FEES*

Annualized Returns



AS OF 09/30/12	1 YR	3 YR	5 YR	7 YR	10 YR
PROPOSAL	14.87%	N/A	N/A	N/A	N/A
PROPOSAL BENCHMARK	14.01%	8.10%	3.69%	5.78%	8.26%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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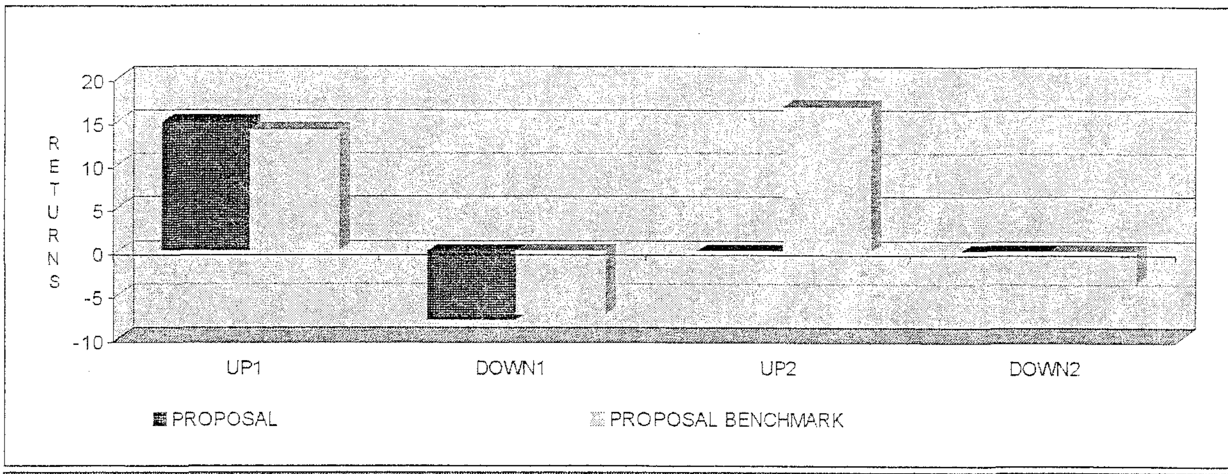
Analysis of Up and Down Markets **



	UP1 09/11-09/12	DOWN1 06/11-09/11	UP2 06/10-06/11	DOWN2 03/10-06/10
PROPOSAL	14.87%	-7.93%	N/A	N/A
PROPOSAL BENCHMARK	14.01%	-7.27%	16.71%	-3.69%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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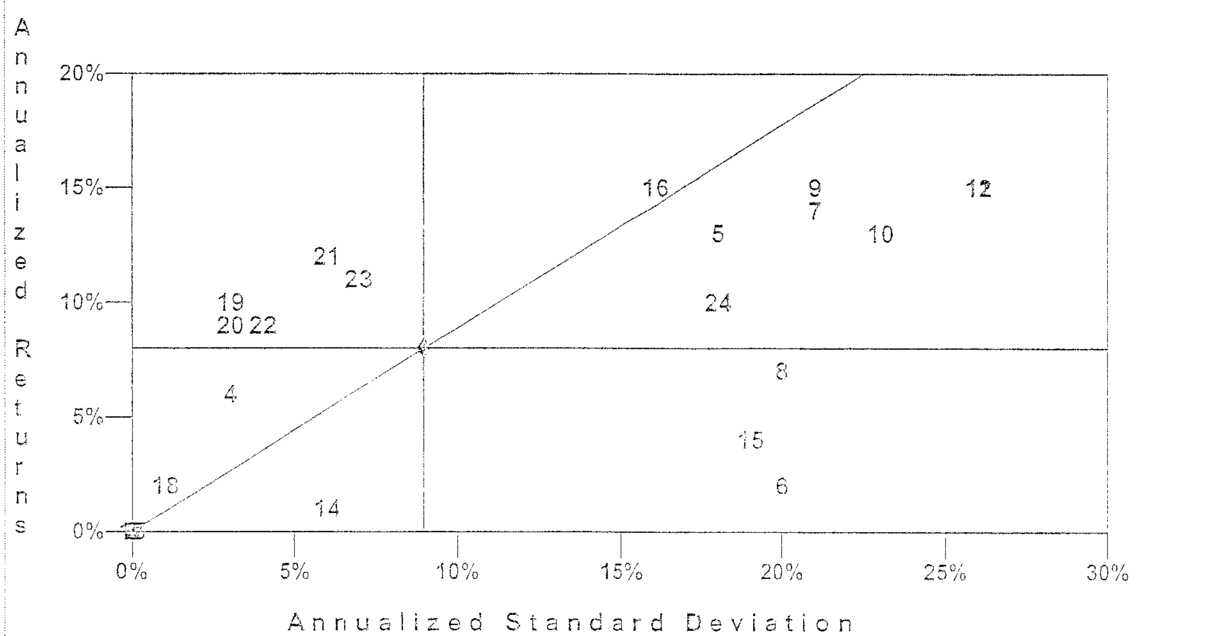
3-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
☆ PROPOSAL	N/A	N/A
◈ PROPOSAL BENCHMARK	8.10%	8.67%
3 90-DAY TREASURY BILLS	0.09%	0.02%
4 LB AGG BOND INDEX	6.19%	2.93%
5 S&P 500 INDEX	13.21%	17.73%
6 MSCI EAFE INDEX - NET OF DIVIDENDS	2.12%	20.06%
7 Winslow Large Cap Growth	14.01%	21.37%
8 NWQ Large Value	7.08%	19.86%
9 Ivy Mid Growth Fd	14.56%	21.03%
10 Mgrs AMG Systematic M V Fd	12.89%	22.98%
11 JP Morgan Dynamic Sm Growth Fd	14.94%	25.53%
12 Cambiar Small Value Fd	14.84%	25.98%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
13 AQR Managed Futures Strat Fd	N/A	N/A
14 Goldman Sachs Abs Return Tr Fd	0.91%	5.56%
15 Thornburg International Val Fd	4.31%	19.30%
16 Virtus Emerging Mkts Opps Fd	14.83%	16.15%
17 Eaton Vance Commodity Strat Fd	N/A	N/A
18 PIMCO Short Term Bond Fd	1.90%	1.26%
19 MetWest Total Rtn Bd Fd	10.09%	2.84%
20 BlackRock Infl Protected Bd Fd	8.72%	2.61%
21 Eaton Vance Inc of Boston Fd	12.20%	6.48%
22 PIMCO Frgn Bd US$ Hedged Fd	8.92%	3.56%
23 Western Em Debt Port Fd	11.15%	7.47%
24 ING Global Real Estate Fd	10.29%	18.07%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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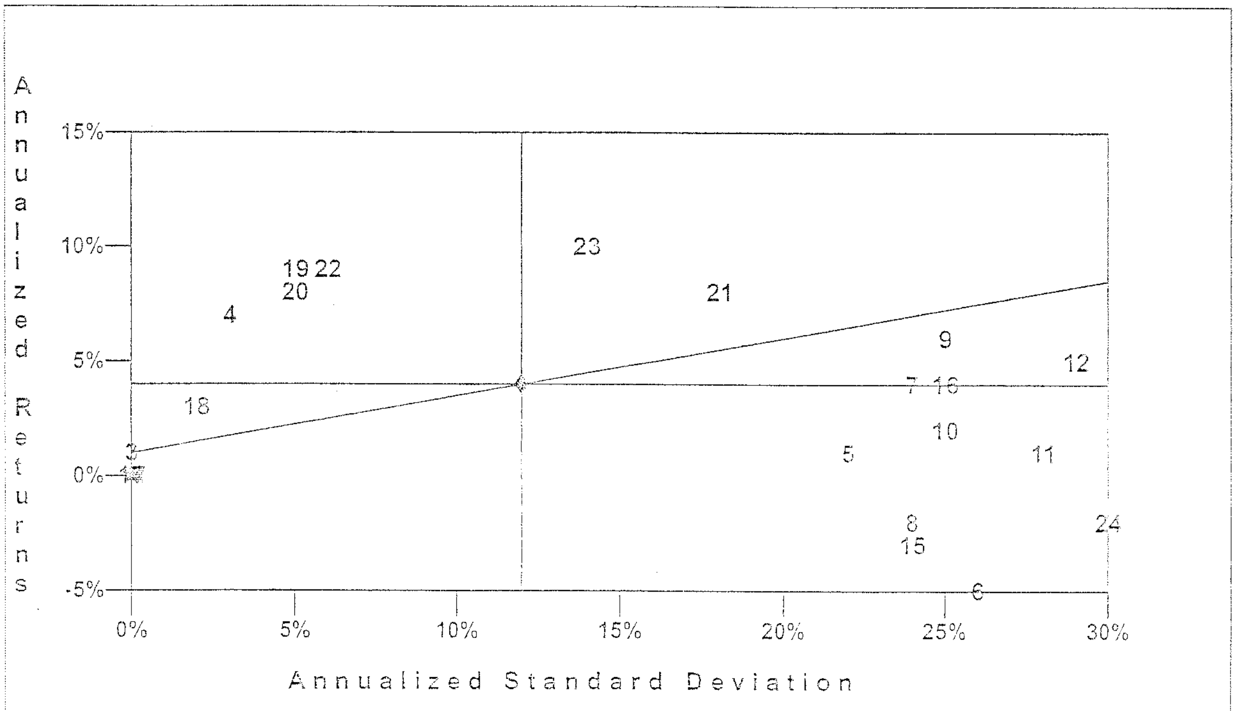
5-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
☆ PROPOSAL	N/A	N/A
◆ PROPOSAL BENCHMARK	3.69%	12.03%
3 90-DAY TREASURY BILLS	0.50%	0.43%
4 LB AGG BOND INDEX	6.53%	3.34%
5 S&P 500 INDEX	1.05%	21.89%
6 MSCI EAFE INDEX - NET OF DIVIDENDS	-5.24%	26.12%
7 Winslow Large Cap Growth	4.09%	23.82%
8 NWQ Large Value	-2.07%	23.51%
9 Ivy Mid Growth Fd	5.79%	24.83%
10 Mgrs AMG Systematic M V Fd	1.63%	24.96%
11 JP Morgan Dynamic Sm Growth Fd	0.76%	27.68%
12 Cambiar Small Value Fd	4.79%	28.73%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

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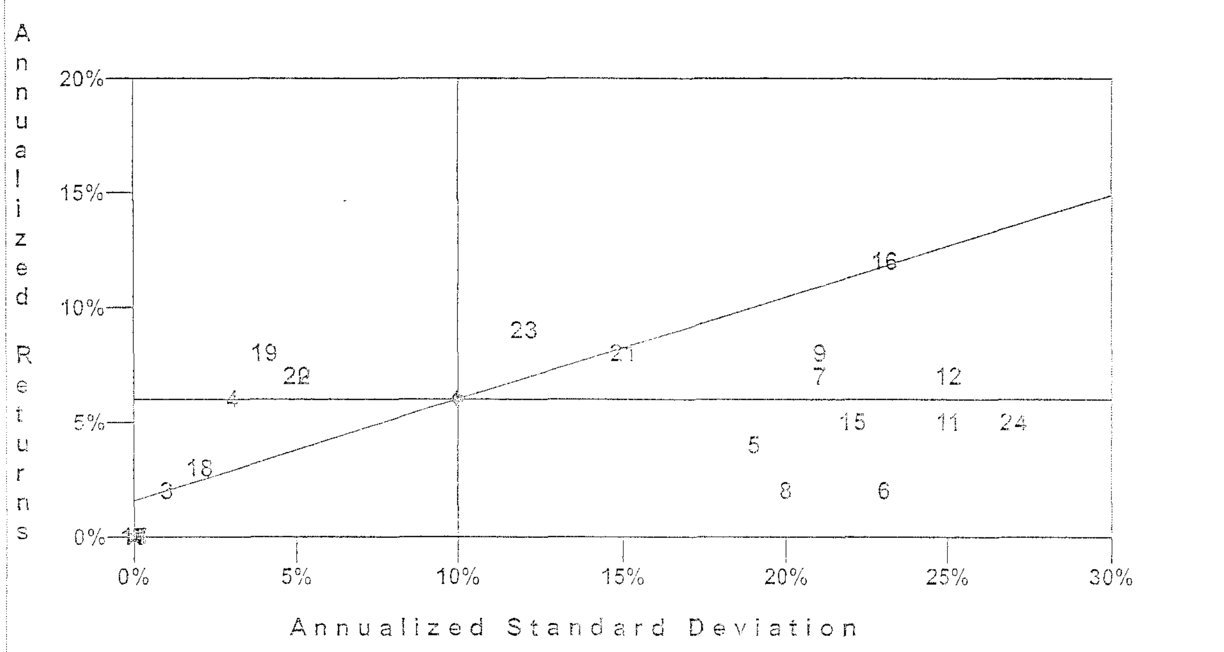
AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
13 AQR Managed Futures Strat Fd	N/A	N/A
14 Goldman Sachs Abs Return Tr Fd	N/A	N/A
15 Thornburg International Val Fd	-3.34%	23.89%
16 Virtus Emerging Mkts Opps Fd	3.98%	24.62%
17 Eaton Vance Commodity Strat Fd	N/A	N/A
18 PIMCO Short Term Bond Fd	2.73%	2.43%
19 MetWest Total Rtn Bd Fd	8.88%	4.65%
20 BlackRock Infl Protected Bd Fd	8.06%	4.59%
21 Eaton Vance Inc of Boston Fd	7.75%	17.85%
22 PIMCO Frgn Bd US$ Hedged Fd	8.51%	5.66%
23 Western Em Debt Port Fd	9.71%	13.96%
24 ING Global Real Estate Fd	-1.94%	29.81%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

7-YEAR RISK/RETURN ANALYSIS BEFORE FEES **



AS OF: 09/30/12	RATE OF RETURN	STANDARD DEVIATION
☆ PROPOSAL	N/A	N/A
♦ PROPOSAL BENCHMARK	5.78%	10.36%
3 90-DAY TREASURY BILLS	1.69%	1.03%
4 LB AGG BOND INDEX	5.92%	3.27%
5 S&P 500 INDEX	4.48%	18.74%
6 MSCI EAFE INDEX - NET OF DIVIDENDS	1.85%	22.78%
7 Winslow Large Cap Growth	7.31%	20.51%
8 NWQ Large Value	2.30%	20.13%
9 Ivy Mid Growth Fd	7.86%	21.23%
10 Mgrs AMG Systematic M V Fd	N/A	N/A
11 JP Morgan Dynamic Sm Growth Fd	5.25%	24.85%
12 Cambiar Small Value Fd	7.24%	25.28%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

AS OF 09/30/12	RATE OF RETURN	STANDARD DEVIATION
13 AQR Managed Futures Strat Fd	N/A	N/A
14 Goldman Sachs Abs Return Tr Fd	N/A	N/A
15 Thornburg International Val Fd	5.21%	21.53%
16 Virtus Emerging Mkts Opps Fd	11.91%	22.59%
17 Eaton Vance Commodity Strat Fd	N/A	N/A
18 PIMCO Short Term Bond Fd	3.16%	2.09%
19 MetWest Total Rtn Bd Fd	8.03%	4.30%
20 BlackRock Infl Protected Bd Fd	6.89%	4.52%
21 Eaton Vance Inc of Boston Fd	7.77%	15.05%
22 PIMCO Frgn Bd US$ Hedged Fd	6.79%	5.15%
23 Western Em Debt Port Fd	9.17%	12.01%
24 ING Global Real Estate Fd	4.90%	26.50%

* Please see the important performance disclosures located at the end of this proposal. Returns, other performance figures and any risk or other statistics based on these performance figures do not reflect the payment of any separate account management fees.

** See discussion of "Up1," "Down1," "Up2," "Down2," "Standard Deviation," "Risk-Return Analysis" and "Proposal Benchmark" in the Glossary of Terms and Disclosures at the end of this proposal.

STEP 4: Ongoing Review Process

After your investment products have been selected, your Financial Advisor will periodically monitor your account's performance. Consulting Group believes that an investment management program does not end with the initial selection of a strategy. Periodic evaluation and monitoring of your account and your long-term investment objectives help you to make periodic adjustments.

Morgan Stanley will provide you with periodic reports showing your account performance. Many Financial Advisors invite clients to review these reports with them either in one-on-one meetings or over the telephone.

Should your financial objectives change, please notify your Financial Advisor so they can reassess your overall investment strategy and suggest appropriate adjustments.

The following services will be provided to you as part of the Select UMA program fee.

Consulting Services

- Define investment objectives and risk tolerance levels
- Develop customized asset allocation strategies
- Recommend appropriate investment products
- Review performance against investment objectives
- Rebalance portfolios periodically (optional)
- Provide manager research reports and periodic economic commentary

Account Services

- Trade executions
- Custody services and safekeeping of securities
- Automatic investment of cash balances

Communications (as required by client)

- Comprehensive periodic reports summarizing performance and portfolio activity
- Monthly account statements
- Trade confirmation of every transaction (unless you request otherwise)
- Periodic review of investment objectives

90-day Treasury Bill Index: An unweighted average of weekly auction offering rates of 90-day Treasury bills. Treasury bills are backed by the full faith and credit of the U.S. government.

Barclays Capital Aggregate Index: The U.S. Aggregate Index covers the dollar-denominated investment-grade fixed-rate taxable bond market, including Treasuries, government-related and corporate securities, MBS pass-through securities, asset-backed securities, and commercial mortgage-based securities. These major sectors are subdivided into more specific subindices that are calculated and published on an ongoing basis. Total return comprises price appreciation/depreciation and income as a percentage of the original investment. This index is rebalanced monthly by market capitalization.

Custom Allocation: Indicates that you have selected the "custom" version of the asset allocation model and have created a customized asset allocation instead of utilizing a model pre-defined by us.

Down1: A portfolio's performance during the most recent "down" cycle in a market. The most recent "down" cycle consists of the most recent quarter in which market performance (as measured by the benchmark) was less than zero. However, if the most recent such quarter was the last in a series of successive quarters in which market performance was less than zero, the most recent "down" cycle consists of that series of successive quarters. (For example, if the last "down" quarter was the fifth successive "down" quarter, then the most recent "down" cycle is the period consisting of those five successive quarters.) The length of the Down1 period may be different from that of the Up1, Up2 and Down2 periods.

Down2: A portfolio's performance during the second most recent "down" cycle in a market. See the definition of "Down1" for how we determine "down" cycles.

FA Discretionary Program: The client has elected to give discretion of the Select UMA account to the Financial Advisor. The FA has ability to select the investment products within the account without the consent of the client. Clients receive a playback of any changes to their account.

Firm Discretionary Program: The client has elected to give discretion of the Select UMA account to Consulting Group. Consulting Group will make the asset allocation and investment product decisions on behalf of the client.

MSCI EAFE Index(Net): The MSCI EAFE Index (Europe, Australasia, Far East) (net) is a free float-adjusted market capitalization index that is designed to measure equity performance of developed markets, excluding the U.S. & Canada. The MSCI EAFE Index consists of the following 22 developed market country indices: Australia, Austria, Belgium, Denmark, Finland, France, Germany, Greece, Hong Kong, Ireland, Israel, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Singapore, Spain, Sweden, Switzerland and the United Kingdom (as of May 2011). Net total return indices reinvest dividends after the deduction of withholding taxes, using(for international indices) a tax rate applicable to non-resident institutional investors who do not benefit from double taxation treaties.

Non-Discretionary Program: The client requires the FA to consult with them before implementing any changes to their account.

Proposal Benchmark: This is a blend of the individual investment products' benchmarks in an allocation equal to the proposal. For example, if the proposal has a 50% US Large Cap Core Equity and a 50% US Core Fixed Income allocation, the Proposal Benchmark would be 50% S&P 500 Index + 50% BC Aggregate Bond Index. The calculation of this blend assumes monthly rebalancing of the weighting of individual product benchmarks back to the target allocation and is likely to differ from actual practice in client accounts. For additional information regarding your Proposal Benchmark, please contact your Morgan Stanley Financial Advisor.

Risk-Return Analysis: On the risk-return graphs, also known as scattergrams or scatterplots, each point on the analysis represents both the return and risk of the proposal and benchmarks. Risk, defined as standard deviation, is measured along the x-axis, while return is measured along the y-axis. The vertical and horizontal lines drawn through the proposal or benchmark divide the graph into four quadrants. The northwest quadrant is sometimes regarded as the most desirable quadrant since any point falling there has both return exceeding the benchmark and less risk than the benchmark. In general, anything plotted to the northwest of another point on the graph is considered to have outperformed the other on a risk-adjusted basis. Historical risk-adjusted performance is not a predictor of future risk-adjusted performance.

S&P 500 Index: Widely regarded as the best single gauge of the U.S. equities market, this world-renowned index includes a representative sample of 500 leading companies in leading industries of the U.S. economy. Although the S&P 500 focuses on the large-cap segment of the market, with over 80% coverage of U.S. equities, it is also an ideal proxy for the total market.

Standard Deviation: The statistical measure of the degree to which an individual value in a probability distribution tends to vary from the mean of the distribution. The standard deviation of performance can be calculated for each security and for the portfolio as a whole. The greater the degree of dispersion, the greater the risk.

Strategic Asset Allocation: A blend of asset classes that we recommend in the Select UMA program to seek to maximize returns in the long run for a given risk tolerance level.

Tactical Asset Allocation: A blend of asset classes that we recommend in the Select UMA program to seek to maximize returns over a shorter period (generally 12 months or so) for a given risk tolerance.

Up1: A portfolio's performance during the most recent "up" cycle in a market. The most recent "up" cycle consists of the most recent quarter in which market performance (as measured by the benchmark) was greater than zero. However, if the most recent such quarter was the last in a series of successive quarters in which market performance was greater than zero, the most recent "up" cycle consists of that series of successive quarters. (For example, if the last "up" quarter was the fifth successive "up" quarter, then the most recent "up" cycle is the period consisting of those five successive quarters.) The length of the Up1 period may be different from that of the Up 2, Down1 and Down2 periods.

Up2: A portfolio's performance during the second most recent "up" cycle in a market. See the definition of "Up1" for how we determine "up" cycles.

IMPORTANT DISCLOSURES

Although the statements of fact and data in this proposal have been obtained from, and are based upon, sources that we believe to be reliable, we do not guarantee their accuracy, and any such information may be incomplete or condensed. All opinions included in this material constitute our judgment as of the date of this material and are subject to change without notice. This material is provided for informational purposes only and is not intended as an offer or solicitation with respect to the purchase or sale of any security. The information shown is provided by the Consulting Group and Sub-Managers and, where provided by Sub-Managers, is not independently verified by us.

Performance. For those Select UMA Sub-Managers that participate in the Morgan Stanley Fiduciary Services program, and beginning with the first full quarter after the acceptance by the Sub-Manager of the first Fiduciary Services client in this style, the composite performance figures represent the Sub-Manager's actual Morgan Stanley Fiduciary Services performance in this style (for all fee paying accounts with no investment restrictions), and are calculated by Morgan Stanley. Performance figures for Sub-Managers that do not participate in the Fiduciary Services program (and for Sub-Managers that do participate in the Fiduciary Services program, performance figures for periods prior to the Sub-Managers participation) are for a composite compiled by the Sub-Manager, and are calculated by the Sub-Manager. Please note that some of the performance information for the Sub-Manager depicts the performance of accounts employing similar, but not the actual, investment strategies that will be used for Select UMA clients. Because the accounts contained in the Sub-Manager's composite were not managed contemporaneously with the Select UMA accounts, may be different in size than a typical Select UMA account or may have been managed with a view toward different client needs and considerations, the specific securities held and rates of return achieved for Select UMA accounts may differ from those of the Sub-Manager's composite. Also, the Sub-Manager's composite may have included IPO investments, while Select UMA accounts do not invest in IPOs. Actual results may vary.

Since Sub-Managers may use different methods of selecting accounts to be included in their performance composites and for calculating performance, returns of different Sub-Managers may not be comparable.

Each Sub-Manager, as investment adviser to the client, will exercise discretion to select securities for the client's account by (i) delivering a model portfolio to the Overlay Manager(which is part of Morgan Stanley), which the Overlay Manager will implement (subject to any client instructions accepted by the Overlay Manager); or (ii) (in the case of an executing Sub-Manager) implementing its investment decisions directly.

The investment results depicted herein represent historical gross performance with no deduction for investment management fees or any applicable insurance or annuity charges. Actual returns will be reduced by expenses, including management fees. Please see the Select UMA ADV brochure for a full disclosure of the fee schedule. Because the fees are deducted quarterly, the fees will have a compounding effect on performance and can be material. For example, on an account with an initial value of $100,000 and a 2% annual fee, if the gross performance is 10% per year over a three-year period, the compounding effect of the fees will result in a net compound rate of return of approximately 7.81% per year over a three-year period, and the total value of the client's portfolio at the end of the three-year period would be approximately $133,100 without the fee and $125,307 with the fee.

Performance results include all cash and cash equivalents, are time weighted, annualized for time periods greater than one year and include realized and unrealized capital gains and losses and reinvestment of dividends, interest and income.

As a result of recent market activity, current performance may vary from the figures shown. Please contact your Financial Advisor for up-to-date performance information. Past performance is not a guarantee of future results. Diversification does not ensure a profit or protect against loss.

General Information. **All Funds are sold by prospectus, which contains more complete information about the fund. Please contact your Financial Advisor for copies. Please read the prospectus and consider the fund's objectives, risks, charges and expenses carefully before investing. The prospectus contains this and other information about the fund.**

Return and principal value of investments will fluctuate and, when redeemed, may be worth more or less than their original cost. Investments are not FDIC insured or bank guaranteed, and investors may lose money. There is no guarantee that past performance or information relating to return, volatility, style reliability and other attributes will be predictive of future results. The value of an investor's shares of any fund will fluctuate and, when redeemed, may be worth more or less than the investor's cost.

If the client selects a "custom" version of the model for the client's unified managed account, unless the client has elected Financial Advisor Discretion, the client (not Morgan Stanley) will determine the initial asset allocation for the model and will be responsible thereafter for any adjustments to the asset allocation of the model. The client's Financial Advisor may utilize recommendations of the our Global Investment Committee ("GIC") as a resource in assisting the client in defining a custom model. If the Financial Advisor does utilize GIC recommendations in connection with defining a custom model, there is no guarantee that any model defined will in fact mirror or track GIC recommendations.

Individual retirement accounts and other retirement plan clients that participate in Morgan Stanley advisory programs may be prohibited from purchasing investment products managed by affiliates of Morgan Stanley.

Morgan Stanley Smith Barney LLC, its affiliates, and its employees are not in the business of providing tax or legal advice. These materials and any tax-related statements are not intended or written to be used, and cannot be used or relied upon, by any taxpayer for the purpose of avoiding tax penalties. Tax-related statements, if any, may have been written in connection with the "promotion or marketing" of the transaction(s) or matters(s) addressed by these materials, to the extent allowed by applicable law. Any taxpayer should seek advice based on the taxpayer's particular circumstances from an independent tax advisor. The performance of tax-managed accounts is likely to vary from that of non-tax managed accounts.

To obtain Tax Management Services, a client must complete the Tax Management Form, and deliver the signed form to us. For more information on Tax Management Services, including its features and limitations, please ask your Financial Advisor for the Tax Management Form. Review the form carefully with your tax advisor. Tax Management Services (a) apply only to equity investments in separate account sleeves of client accounts; (b) are not available for all accounts or clients; and (c) may adversely impact account performance. Tax Management Services do not constitute tax advice or a complete tax-sensitive investment management program. There is no guarantee that Tax Management Services will produce the desired tax results.

January 8, 2013

Investing in the market entails the risk of market volatility. The value of all types of securities, including Funds, may increase or decrease over varying time periods.

To the extent the investments depicted herein represent international securities, you should be aware that there may be additional risks associated with international investing, including foreign economic, political, monetary and/or legal factors, changing currency exchange rates, foreign taxes, and differences in financial and accounting standards. These risks may be magnified in emerging markets. International investing may not be for everyone. Small and mid-capitalization companies may lack the financial resources, product diversification and competitive strengths of larger companies. In addition, the securities of small capitalization companies may not trade as readily as, and be subject to higher volatility than, those of larger, more established companies.

Ultra-short bond funds are Funds that generally invest in fixed income securities with very short maturities, typically less than one year. They are not money market funds. While money market funds attempt to maintain a stable net asset value, an ultra-short bond fund's net asset value will fluctuate, which may result in the loss of the principal amount invested. They are therefore subject to the risk associated with debt securities such as credit and interest rate risk.

Bonds are subject to interest rate risk. When interest rates rise, bond prices fall; generally, the longer a bond's maturity, the more sensitive it is to this risk. Bonds may also be subject to call risk, which allows the issuer to retain the right to redeem the debt, fully or partially, before the scheduled maturity date. Proceeds from sales prior to maturity may be more or less than originally invested due to changes in market conditions or changes in the credit quality of the issuer. High-yield bonds are subject to additional risks such as increased risk of default and greater volatility because of the lower credit quality of the issues.

In unified managed account programs at Morgan Stanley, alternative investments are limited to primarily U.S.-registered open-end mutual funds and exchange-traded funds (ETFs) that seek to pursue alternative investment strategies or returns. Mutual funds in this category may employ various investment strategies and techniques for both hedging and more speculative purposes, such as short selling, leverage, derivatives and options, which can increase volatility and the risk of investment loss. Alternative investments are not suitable for all investors.

Investing in commodities entails significant risks. Commodity prices may be affected by a variety of factors at any time, including, but not limited to, (i) changes in supply and demand relationships, (ii) governmental programs and policies, (iii) national and international political and economic events, war and terrorist events, (iv) changes in interest and exchange rates, (v) trading activities in commodities and related contracts, (vi) pestilence, technological change and weather, and (vii) the price volatility of a commodity. In addition, the commodities markets are subject to temporary distortions or other disruptions due to various factors, including lack of liquidity, participation of speculators and government intervention.

The risks of investing in REITs are similar to those associated with direct investments in real estate: lack of liquidity, limited diversification, and sensitivity to economic factors such as interest rate changes and market recessions.

Derivatives, in general, involve special risks and costs that may result in losses. The successful use of derivatives requires sophisticated management in order to manage and analyze derivatives transactions. The prices of derivatives may move in unexpected ways, especially under abnormal market conditions. In addition, correlation between the particular derivative and an asset or liability of the investment portfolio may not be what the investment manager expected. Some derivatives are "leveraged" and therefore may magnify or otherwise increase investment losses. Other risks include the potential inability to terminate or sell derivative positions, as a result of counterparty failure to settle or other reasons.

In this proposal, "Morgan Stanley," "we," "us," or "our" apply to Morgan Stanley Smith Barney LLC.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
BOB STUMP – CHAIRMAN
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET No. E-01933A-12-0291

Direct Testimony of

Malissa Buzan

On Behalf of

Cynthia Zwick

January 10, 2013

Q. Please state your name and address.

A. My name is Malissa Buzan, and my address is 5515 S. Apache Avenue, Suite 200, Globe, Arizona 85501.

Q. Have you ever testified before the Arizona Corporation Commission?

A. I have not provided testimony in any cases before, but I have provided public comment on several occasions.

Q. By whom are you employed?

A. I am employed as the Acting Director of the Gila County Community Services Department, and I serve as President of the Arizona Community Action Association (ACAA).

Q. In what capacity are you testifying today?

A. I am testifying as the President of Arizona Community Action Association (ACAA).

Q. What is the mission of Arizona Community Action Association?

A. Our missions is advocating, educating and partnering to prevent and alleviate poverty, and we administer a number of programs to help individuals and families access the tools they need to become self-sufficient, including the Home Energy Assistance Fund.

Q. What is the Home Energy Assistance Fund?

A. It is the first warm weather fuel fund which leverages various fund sources, including utility funding, in order to assist families with the payment of their utility bills and with weatherization. We work with community partners throughout the state, including faith based organizations, to provide bill assistance and weatherization services. Actually, Mr. Jones provides a wonderful description in his testimony.

Q. Why are you testifying today?

A. As President of ACAA and as someone who works with low-income families every day, I am testifying today in order to support Cynthia Zwick's recommendation that the $4.5 million LIFE fund be provided to ACAA for investment and for ongoing and sustainable support for TEP's low income customers.

Q. Why do you believe ACAA is an appropriate organization to manage these funds?

A. ACAA conceived of and created the Home Energy Assistance Fund in 2004 and has been an affective trustee of the funds we have received, investing those funds, growing our investment, and expanding our partner networks statewide in order to effectively serve families in need of assistance.

Q. Are you aware of what TEP is proposing to do with the LIFE fund in this case?

A. I am, and I support the alternative suggestion proposed by Ms. Zwick for a couple of reasons. First, Ms. Zwick's proposal will allow for the use of the $4.5 million as it was originally intended to be used – helping vulnerable customers in the TEP territory. Second, through ACAA's investment and management of these funds, this program will sustain itself for years to come, provide more funding than currently available through the fund, and continue to provide funding to those customers who struggle. While it is my hope that someday fewer and fewer customers will need any assistance, history indicates that due to a variety of reasons, members of our community will continue to struggle periodically, and there needs to be assistance so they may remain safe and healthy during those difficult times.

Q. Does ACAA have the capacity to manage these funds effectively?

A. We do. Our Board and staff work with Charles Collins of Smith Barney Morgan Stanley on our investments, and have been able to not only sustain but grow the funds for which we are currently responsible, allowing more families to be served.

Q. Does this conclude your testimony?

A. Yes, it does, thank you.

zmck-2

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
BOB STUMP, CHAIRMAN
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-12-0291

TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT

CYNTHIA ZWICK
FEBRUARY 15, 2013

EXHIBIT
Zwick-2
ADMITTED

Q. Please state your name for the record.

A. Cynthia Zwick

Q. Have you previously filed testimony in this case?

A. Yes. I filed direct testimony on January 11, 2013.

Q. What is the purpose of this additional testimony?

A. My testimony at this time is intended to articulate my support for the Settlement Agreement filed in this case.

Settlement discussions began in this case on January 15, 2013, with all parties receiving notice and an opportunity to participate. I was able to fully participate in these discussions in order to share my position and concerns about the case as originally filed.

Arizonans throughout the Tucson Electric Power (TEP) service territory continue to struggle to find jobs, to maintain their homes, to feed their families, in short to simply make ends meet, and are also unable to maintain utility service. The parties signing the Settlement Agreement in this case have agreed that circumstances are such that in order to maintain the economic viability of the Company, ensure that low and formerly middle income families realize reasonable rates, are subject to fair practices and procedures, and have additional support available in order to ensure consistent and continued electric service. These parties have entered into the agreement that is before the Commission.

The provisions in this case related to low-income customers that all settling parties have agreed to support the following provisions relating to low-income customers:

- Tucson Electric Power will make an annual contribution of $150,000 to Arizona Community Action Association to fund low-income utility bill assistance programs, commencing on September 1, 2013;

- TEP will limit a typical Lifeline customer's increase to an amount that is reflective of the average monthly dollar increase of a standard R-01 customer;
- Lifeline customers will be subject to both the PPFAC and DSM surcharges; and
- The Lifeline rates currently in place will continue to survive this case though most will become frozen rates (which will, through attrition phase out over time) with the conditions and discounts applying to all existing and continuing Lifeline rates.

My Direct Testimony and participation in this case was exclusive to the impact of this rate increase on low-income customers.

I offer my full support to the agreements reached with respect to the Low-Income issues listed above and thank the Parties to this Settlement for their considered position and urge the support of the Commission as well.

Q. Does this conclude your testimony?

A. Yes, it does.

RESPECTFULLY SUBMITTED this 15th day of February, 2013.

By ______________________
Cynthia Zwick
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ORIGINAL and thirteen (13) COPIES of the Foregoing were filed with docket control this 15th day of February, 2013.

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